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December 15, 2010

The Honorable Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Northern Pass Transmission LLC, Docket No. ER11-____-000

Dear Ms. Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] Part 35 of the Commission's regulations,[2] and the Commission's orders in *Northeast Utilities Service Co. and NSTAR Electric Co.*, 127 FERC ¶ 61,179, *reh'g denied*, 129 FERC ¶ 61,279 (2009), Northern Pass Transmission LLC ("Northern Pass") submits for filing a bilateral, cost-based transmission service agreement ("TSA") executed on October 4, 2010 by Northern Pass and H.Q. Hydro Renewable Energy, Inc. ("HQ Hydro Renewable") for service over the Northern Pass Transmission Line (the "NPT Line").

[1] 16 U.S.C. § 824d (2006).

[2] 18 C.F.R. Pt. 35 (2010).

Northern Pass requests an effective date for the TSA of February 14, 2011, which is 61 days after the date of this filing. This effective date is necessary to trigger various provisions of the TSA that commit the parties to move forward with the design, siting and construction of the NPT Line. In addition, this effective date is necessary to permit the termination cost recovery provisions of the TSA to go into effect and to permit Northern Pass to establish a regulatory asset for pre-commercial operation costs that are not recorded in FERC Account No. 107 (Construction Work in Progress). Northern Pass requests a waiver of the Commission's regulations at 18 CFR § 35.13 to permit the TSA to become effective prior to the construction of the NPT Line. HQ Hydro Renewable fully supports this filing, including the proposed effective date, as evidenced by its execution of the TSA.

The NPT Line consists of (i) a proposed 1,200 MW high voltage direct current ("HVDC") transmission line from the United States-Canadian border to a converter station to be constructed in the City of Franklin, New Hampshire, and (ii) a radial 345 kV alternating current ("AC") transmission line between the Franklin converter station and the Public Service Company of New Hampshire ("PSNH") Deerfield substation in the town of Deerfield, New Hampshire (the "AC Line"). The NPT Line, which has an estimated cost of $1.1 billion, will interconnect at the United States-Canadian border with a new HVDC transmission line to be owned and constructed in Québec by Hydro-Québec TransÉnergie ("TransÉnergie"), the transmission division of Hydro-Québec, a body

politic and corporate, incorporated and regulated by the Hydro-Québec Act (R.S.Q., Chapter H-5). Under the TSA, Northern Pass will sell 1,200 MW of firm transmission service over the NPT Line to HQ Hydro Renewable over a 40-year term for the purpose of permitting the delivery of low carbon, predominantly hydro-electric power from Hydro-Québec to New England's electricity grid and increasing competitive supply options for load serving entities and other purchasers of energy in New England. The TSA will also permit HQ Hydro Renewable to deliver power from New England to the U.S. border for export into Québec.

As shown below, the TSA should be approved in its entirety as a *Mobile-Sierra* contract since it is a voluntarily negotiated agreement between Northern Pass and HQ Hydro Renewable under which HQ Hydro Renewable will pay for the NPT Line through a cost-based rate that will allow Northern Pass to recover its investment in the NPT Line, a return on its investment, and all of its prudently incurred operating costs and other expenses. In the alternative, even if the TSA is reviewed under the standards applied by the Commission for agreements that do not initially receive *Mobile-Sierra* protections, it is just and reasonable and consistent with Commission policy and should be accepted or approved on that basis. In support of such approval, Northern Pass has included information required by Commission Order No. 679,[3] to justify three TSA provisions that

[3] *Promoting Transmission Inv. through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

could be characterized as transmission "incentives" under Order No. 679. If the Commission does not accept the three TSA incentives under Order No. 679, Northern Pass alternatively requests the Commission to grant the incentives under its public policy standards under FPA Section 205 in light of the significant public benefits produced by the NPT Line.[4]

I. EXECUTIVE SUMMARY

In Orders issued on May 22, 2009 and December 29, 2009, the Commission approved a Petition for Declaratory Order in which Northeast Utilities Service Company ("NUSCO") and NSTAR Electric Company ("NSTAR Electric") (collectively "Petitioners") requested the Commission to approve the structure of a transaction involving a proposed new transmission project interconnecting New England and Québec that includes a long-term, bilateral transmission service agreement.[5] The Commission granted the Petition for Declaratory Order. It held that the proposed new transmission line was a participant-funded project, and that the Petitioners could enter into a bilateral, cost-based transmission service agreement with a subsidiary of Hydro-Québec under

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[4] *See, e.g.*, *S. Cal. Edison Co.*, 133 FERC ¶ 61,107 (2010).

[5] *Ne. Utils. Serv. Co. and NSTAR Elec. Co.*, 127 FERC ¶ 61,179 ("May 22 Order"), *reh'g denied*, 129 FERC ¶ 61,279 ("December 29 Order") (collectively, the "Approval Orders"). While NUSCO and NSTAR were the petitioners in the Petition for Declaratory Order, the entity that is the party to the TSA is Northern Pass, a joint venture between subsidiaries of NU and NSTAR Electric. Similarly, the Petition referred to H.Q. Energy Services (U.S.) Inc. ("HQUS"), a U.S. subsidiary of Hydro-Québec, whereas the entity that is party to the TSA is HQ Hydro Renewable, a newly formed U.S. subsidiary of Hydro-Québec and an affiliate of HQUS. NU and NSTAR are informed that HQ Hydro Renewable intends to obtain market-based rate authorization to enable it to make sales of the power transmitted through the NPT Line.

which they would sell 1,200 MW of firm transmission service over the new transmission line in return for agreement by the Hydro-Québec subsidiary to pay for the cost of the line.[6]

Following the issuance of the Commission's orders, the Petitioners formed Northern Pass, and representatives of Northern Pass and H.Q. Energy Services (U.S.) Inc. ("HQUS") engaged in approximately one year of negotiations with respect to the rates, terms and conditions of the TSA. On October 4, 2010, Northern Pass and HQUS's newly formed affiliate, HQ Hydro Renewable, executed the TSA. In accordance with the Approval Orders, Northern Pass is filing the TSA for the Commission's review and acceptance under FPA Section 205.

The TSA is a unique and comprehensive, 185-page contract that was meticulously negotiated by the parties in order to allocate the risks associated with the development, construction and operation of the NPT Line. Under the TSA and as more fully described herein, HQ Hydro Renewable will be responsible for approximately $1.1 billion in initial construction costs and a return on such costs, plus necessary additional capital expenditures and return, operation and maintenance expenses, administrative and general expenses, tax expense, and other expenses associated with the NPT Line over the 40-year operating term of the contract. The TSA carefully sets forth the standards and procedures applicable to Northern Pass's activities as a transmission service provider and allocates to

[6] December 29 Order at P 3.

Northern Pass the risks and costs resulting from any mismanagement of its responsibilities using a prudence standard.

The charges under the TSA will be calculated using a formula rate that is consistent with the Commission's standards for cost-based transmission service rates. The parties to the TSA have agreed that Northern Pass will apply a 12.56 percent return on equity ("ROE") to calculate an Allowance for Funds Used During Construction ("AFUDC") during the construction period. Upon commercial operation of the NPT Line, the TSA provides that the ROE will be adjusted to be equal to the then-effective base ROE approved for regional transmission service under the ISO New England Inc. ("ISO-NE") Open Access Transmission Tariff ("OATT") plus an adder of 142 basis points (which is equivalent to an RTO participation adder of 50 basis points plus an investment incentive adder of 92 basis points, as described and supported below), subject to a requirement that the total ROE not exceed the applicable Commission-established zone of reasonableness. The TSA reflects HQ Hydro Renewable's role as the customer for firm transmission for the forty-year term of the agreement, as well as numerous compromises between the parties in order to allocate business and commercial risks. It carefully delineates the parties' rights and responsibilities during various project phases. Appendix A-1 to this filing contains a detailed summary of the TSA.

As described in the attached Testimony of James A. Muntz (Exh. No. NPT-200), the TSA promotes the public interest by providing a number of important benefits,

including supporting environmental and public policy objectives relating to the use of low carbon energy to produce electricity, diversifying New England's power supply mix, and enhancing competitive regional electric markets by increasing supply alternatives. A study performed by Charles River Associates ("CRA") shows that the expanded import capability provided by the NPT Line will reduce locational marginal prices for energy in New England by eliminating congestion between New England and Québec that is limiting economic transactions between the two regions. The NPT Line will provide New England with access to a competitively priced, reliable supply of energy from Hydro-Québec's resources that include very little fossil-fueled generation. The power delivered over the NPT Line will be predominantly hydro-electric energy. This energy will be supported by power from an electric system that includes over 40,000 MW of generating capacity. By allowing 1,200 MW of power to flow into New England, the NPT Line will help avoid or defer the need to construct fossil fuel generation plants that would otherwise be required to produce energy to serve New England consumers' growing demand.

This transaction will have no impact on the rates for transmission service under the ISO-NE OATT. None of the costs of the NPT Line or any ISO-NE-required or HQ Hydro Renewable-requested upgrades associated with the TSA will be rolled into the regional or local transmission rates charged under the ISO-NE OATT to regional and

local customers.[7] The TSA obligates HQ Hydro Renewable to pay 100 percent of the capital and operating costs of the NPT Line and of any upgrades under the TSA, and HQ Hydro Renewable will have to recover these costs through competitive sales of wholesale power.

The structure of the accompanying power sales transactions as described in the Petition for Declaratory Order proceeding (Docket No. EL09-20) has changed since the Commission issued the two Approval Orders. In the Petition for Declaratory Order, it was then expected that a subsidiary of Hydro-Québec would enter into one or more long-term power purchase and sales agreements ("PPAs") with load-serving entities in New England to sell the throughput of the NPT Line. Currently, HQ Hydro Renewable intends to sell most of the power transmitted over the NPT Line into the ISO-NE markets,[8] and will thus bear the full risk of selling its generation, inclusive of transmission costs associated with the NPT Line, at prevailing market prices. This change from the power sale arrangement originally described in the Petition for Declaratory Order ensures that HQ Hydro Renewable will bear the entire risk of cost recovery for the NPT Line through competitive power sales into the ISO-NE energy

[7] This is true unless ISO-NE determines that the costs of the AC Line or any upgrade should receive regional rate treatment and HQ Hydro Renewable does not choose to pay the costs of such upgrades and acquire the rights associated with making such payments.

[8] HQ Hydro Renewable may enter into a PPA with PSNH for a small portion of the power delivered over the NPT Line, subject to state commission approval.

market and that no New England customers will be compelled to purchase Hydro-Québec power delivered over the NPT Line at an above-market price.

The Commission should summarily approve the TSA in its entirety as a *Mobile-Sierra* contract, as *Mobile-Sierra* has been clarified and applied by the Supreme Court in two recent decisions, *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 128 S. Ct. 2733 (2008) ("*Morgan Stanley*") and *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 130 S. Ct. 693 (2010) ("*NRG Power Marketing*"). The TSA is an executed, bilateral contract between two sophisticated parties who have agreed upon a negotiated allocation of costs and risks associated with a voluntary commercial transaction that benefits both parties. Moreover, because HQ Hydro Renewable is bearing the entire cost of transmission service and must recover those costs from power sales to willing buyers, there can be no legitimate contention that approval of the TSA could "seriously harm[] the consuming public."[9]

If the Commission does not approve the TSA in its entirety as a *Mobile-Sierra* contract, the Commission should nonetheless find that the TSA is just and reasonable under the Federal Power Act and is in accord with the Commission's policies and goals as to its rates, terms and conditions. Thus, the Commission should accept it as submitted. The TSA represents a carefully negotiated commercial arrangement in which the two parties have allocated the unique risks associated with this transaction in an equitable

[9] *Morgan Stanley*, 128 S. Ct. at 2746.

manner. There would be no basis for the Commission to find that the TSA imposes an unjust and unreasonable burden on the purchaser of the transmission service, HQ Hydro Renewable. Northern Pass bears considerable risk under the TSA (as described in the attached testimony of Messrs. Auseré and Lubbock) and must comply with the same prudence standard that is applied to other transactions subject to the Commission's Section 205 and 206 jurisdiction.[10] The rates charged by Northern Pass are cost-based and the formula rate in the TSA comports with the Commission's standards for cost-based rates. The proposed ROE is also just and reasonable as it lies within the zone of reasonableness established by the Discounted Cash Flow ("DCF") study presented with this filing and represents a fair return based on the unique allocation of risks in this contract.

If the Commission does not approve the TSA based on the fact that it is a bilaterally-negotiated *Mobile-Sierra* contract, Northern Pass has included with this application testimony and exhibits supporting the justness and reasonableness of the rate and accounting mechanisms and other operational provisions of the TSA. Northern Pass has also included in this filing materials and information in support of three aspects of the TSA that could be characterized as transmission incentives under Order No. 679: (1) an ROE of 12.56 percent during the construction period for purposes of calculating AFUDC, and upon commercial operation, an ROE equal to the base ROE under the ISO-NE

[10] TSA, § 8.1.4.

regional rates plus an adder of a total of 142 basis points, subject to a cap at the high end of the zone of reasonableness; (2) the parties' termination rights under the TSA under certain limited circumstances, which provide Northern Pass the right to recover its costs in the case of termination of the project; and (3) the establishment of a regulatory asset for costs incurred prior to commercial operation and which are not included in FERC Account No. 107 as Construction Work in Progress ("CWIP").[11]

As demonstrated below and in the accompanying testimonies and supporting materials, the NPT Line meets the Order No. 679 standards. It is a large scale, non-routine transmission project that will provide broad regional benefits to New England consumers. It is a major, international transmission project involving construction in two countries, and as such, will be subject to extensive reviews and assessments by federal agencies and state regulatory authorities in the United States and by regulatory authorities in Canada, and therefore the project presents unique and significant risks and challenges. If and to the extent necessary, the Commission should therefore approve the incentive rate provisions in the TSA.[12]

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[11] As discussed in Section VIII and Exh. No. NPT-500 at 13-17 (Griffin), the TSA provides for the establishment of a regulatory asset to recover the estimated costs to decommission the NPT Line over the last five years of the forty-year term of the TSA. Northern Pass does not believe the establishment of this regulatory asset is an incentive under Order No. 679.

[12] Section 2.1(a) of the TSA provides that Northern Pass shall file the TSA with the Commission within sixty days after the date of execution. The parties, however, have agreed to an extension for filing the TSA.

II. CONTENTS OF FILING

Northern Pass describes its proposal in detail in the following:

- This Transmittal Letter;
- Appendix A – Transmission Service Agreement (designated as Northern Pass Transmission LLC Rate Schedule No. 1) and Summary of the TSA (Appendix A-1) (Exhibit No. NPT-100);
- Appendix B – Direct Testimony and Exhibits of James A. Muntz (project description, project benefits, risks and challenges of the project, and advanced technology) (Exhibit Nos. NPT-200 to 208);
- Appendix C – Joint Direct Testimony of Michael J. Auseré and Geoffrey O. Lubbock (description of Northern Pass as a start-up company, and financial risks and challenges to Northern Pass) (Exhibit Nos. NPT-300 to 302);
- Appendix D – Direct Testimony of Paula M. Taupier (discussion of formula rate under TSA) (Exhibit Nos. NPT-400 to 402);[13]
- Appendix E – Direct Testimony of Timothy J. Griffin (Northern Pass's proposed accounting procedures) (Exhibit No. NPT-500);
- Appendix F – Direct Testimony and Exhibits of Dr. William E. Avera (ROE) (Exhibit Nos. NPT-600 to 614);
- Appendix G – LMP and Congestion Impacts of Northern Pass Transmission Project, Report by Charles River Associates, Inc. regarding congestion reduction benefits of the NPT Line (Exhibit No. NPT-700);
- Appendix H – Attestation required by 18 C.F.R. § 35.13(d)(6); and
- Appendix I – Service List.

[13] Ms. Taupier sponsors revenue impact statements for the first full calendar year of commercial operation for the NPT Line, as set forth in Exhibit No. NPT-401.

III. BACKGROUND

A. Prior FERC Orders

In Docket No. EL09-20, the Commission addressed a Petition for a Declaratory Order filed by NUSCO and NSTAR Electric to construct a new, participant-funded HVDC transmission tie line connecting the New England transmission system with the TransÉnergie transmission system in Québec. The proposed new line would provide New England consumers with access to low carbon, predominantly hydro-electric power from Québec. Petitioners explained that Hydro-Québec is currently developing over 4,000 MW of new hydro-electric generation and expects to have a significant surplus of capacity that will be available for export to New England for the next several decades. Petitioners also explained that the available transfer capacity of the existing transmission lines between Québec and New England are inadequate to support the delivery of this surplus power.[14] Petitioners asked the Commission to rule on whether NUSCO and NSTAR Electric may enter into a bilateral transmission service agreement with HQUS, a wholly-owned subsidiary of Hydro-Québec, under which they would sell 1,200 MW of firm transmission service over the new transmission line.

[14] Currently, New England has two HVDC interconnections with Québec: (1) a 225 MW back-to-back converter at Highgate in northern Vermont and (2) a +/- 450 kV HVDC line with terminal configurations allowing up to 2,000 MW to be delivered at Sandy Pond in Massachusetts. The capacity on these existing lines is currently mostly subscribed.

The Commission granted the Petition for Declaratory Order and approved the proposed structure of the transaction. The Commission recognized that, to achieve a transaction of the scale and complexity contemplated by the proposed transaction, the parties should have the flexibility to negotiate unique rates, terms and conditions rather than sell transmission service pursuant to the ISO-NE OATT.[15] The Commission ruled that Petitioners may enter into a bilateral transmission service agreement with HQUS, subject to the Commission's review thereof under Section 205.[16]

The Commission also found that the Petitioners' proposed project is "a cost-based participant-funded transmission project that the Petitioners are undertaking at the request of HQUS who has agreed to participant fund the project."[17] The Commission rejected arguments that the project should be treated as a merchant transmission project and therefore should be made subject to open season requirements with respect to the first 1,200 MW of capacity. The Commission stated that it "has imposed open season requirements when a merchant transmission project developer has proposed providing transmission access at negotiated rates as a way to ensure against undue discrimination."[18] However, the Commission stated that this is not a merchant project because, unlike a merchant transmission project where the developers assume all of the

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[15] May 22 Order at P 42; December 29 Order at P 24.

[16] May 22 Order at P 42.

[17] *Id.* at P 41.

[18] *Id.* at P 29.

market risk, "the risks of the Project have been shifted from the Petitioners to HQUS, which has agreed to participant fund the Project, and thus has full financial responsibility for the Project."[19]

The Commission further found that "[a]ny other potential developer has the same right to request transmission service necessary to interconnect new generation resources to the Petitioners' systems. Under Order No. 888, the Petitioners retain the obligation to undertake any necessary system expansion at the higher of incremental or embedded cost."[20]

B. Description of Northern Pass and Its Members

Northern Pass is a single purpose, limited liability company organized in New Hampshire to develop, design, construct, own, and maintain the NPT Line. Northern Pass's principal place of business is at Energy Park, 780 North Commercial Street, Manchester, NH 03101. Northern Pass is owned 75 percent by NU Transmission Ventures, Inc. ("NU Ventures"), a wholly-owned subsidiary of NU, and 25 percent by

[19] *Id.* at P 41.

[20] *Id.* at P 29.

NSTAR Transmission Ventures, Inc. ("NSTAR Ventures"), a wholly-owned subsidiary of NSTAR.[21]

Northern Pass will have a "Members Committee," which will be the principal decision-making body of the LLC. The Members Committee consists of four representatives, two appointed by NU Ventures and two by NSTAR Ventures. Northern Pass is currently expected to have no operating employees; however, it will have access to the utility expertise it needs through a service contract with NUSCO for services such as corporate and secretarial, financial planning, accounting and taxes, insurance, budgets, data processing, operations, engineering research and standardization, and other administrative services. Northern Pass will be capitalized initially through a combination of equity contributions from Northeast Utilities ("NU") and NSTAR and debt financing obtained by Northern Pass. Under the TSA, Northern Pass has a contractual obligation to use commercially reasonable efforts to maintain a 50 percent debt/50 percent equity capital structure, including during the construction phase. In that respect, the TSA requires Northern Pass to enter into an equity agreement with NU and NSTAR under which NU and NSTAR will commit to provide, annually during the construction phase, equity capital consistent with Northern Pass's obligation to maintain a 50 percent debt/50 percent equity capital structure.

[21] On October 18, 2010, NU and NSTAR announced that they have entered into an agreement under which they will merge with one another, subject to approval by shareholders and federal and state regulators.

C. Description of HQ Hydro Renewable

HQ Hydro Renewable is a corporation organized and existing under the laws of the State of Delaware. It is a newly created, indirect wholly-owned subsidiary of Hydro-Québec. HQ Hydro Renewable, which will be the purchaser of transmission rights on the NPT Line, will purchase power at the U.S./Canadian border from its parent and/or its affiliate(s) and will market the power it transmits on the NPT Line to customers in New England. It will also have the ability to transmit power from south-to-north on the NPT Line and to sell power at the U.S. border into Québec.

Hydro-Québec, as the parent of HQ Hydro Renewable, is one of the largest power generators in North America, controlling approximately 44,000 MW of generation. The vast majority of Hydro-Québec's system power is generated by hydro-electric facilities,[22] and Hydro-Québec is currently constructing additional hydro-electric generation. The small remainder is generated by a mix of wind, thermal, and nuclear power facilities. Hydro-Québec has been selling power to the New England energy markets for the past several decades over the existing transmission lines interconnecting the two regions.

D. Description of the NPT Line and Related AC Upgrades

The NPT Line is the United States portion of the new HVDC transmission interconnection that will link the TransÉnergie transmission system in Québec to the New

[22] *See* Exh. No. NPT-700 at 5 (CRA Report) (noting that Hydro-Québec owns and operates 34,499 MW of hydroelectric generating stations and has contracts to purchase another 5,428 MW of hydroelectric generating capacity).

England transmission system. TransÉnergie will develop, construct, own and maintain the Canadian portion of this new transmission line, which will extend from the Des Cantons substation to the U.S. Border (the "Québec Line").[23] TransÉnergie and Northern Pass will work cooperatively to develop, design and site the Québec Line and the NPT Line.[24]

The NPT Line consists of a proposed 1,200 MW +/- 300 kV HVDC transmission line extending from the United States border to a new direct current ("DC") to alternating current ("AC") converter station to be located near the Webster substation in the City of Franklin, New Hampshire (the transmission line and converter station are referred to in this filing as the "HVDC Line").[25] The length of the U.S. HVDC portion of the NPT Line is approximately 140 miles. The converter station has an estimated cost of between $250 million and $350 million and is necessary to convert power from direct current to alternating current that is synchronized with the eastern interconnection. It will be designed to be capable of supporting bi-directional power flows from and to the 345-kV AC system operated by ISO-NE.

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[23] NUSCO and TransÉnergie will coordinate to plan, site, engineer, develop, permit, construct and operate the NPT Line and the Québec Line. *See* Exh. No. NPT-200 at 4-7 (Muntz).

[24] Exh. No. NPT-200 at 7-8 (Muntz).

[25] The maximum north-south, long-term firm available transfer capability for the NPT Line will be 1,200 MW based on studies that have been performed by ISO-NE for the existing HQ-New England HVDC tie line. The studies have shown that a contingency causing the outage of the HQ-New England HVDC tie-line when there is more than 1,200 MW of power being transferred from Hydro-Québec into New England over a single interconnection can result in voltage instability in PJM and New York.

In order to interconnect the HVDC Line with the bulk power system in New England in a reliable manner, Northern Pass has determined (and HQ Hydro Renewable has agreed) that it is necessary to construct the AC Line, a 40-mile, radial 345 kV AC transmission line extending from the southern terminus of the HVDC Line (i.e., at the converter station in Franklin, New Hampshire) to an existing PSNH substation located in Deerfield, New Hampshire. This AC radial line is considered part of the NPT Line and will be paid for by HQ Hydro Renewable under the TSA. The delivery point for transmission service under the TSA will be at the Deerfield substation, where power can be injected directly into or from the ISO-NE operated network.

In addition to the AC Line, the parties to the TSA have taken into consideration the possibility that ISO-NE may require certain additions, modifications, or reinforcements to AC network transmission facilities in New England to be constructed in order to satisfy the requirements of Section I.3.9 of the ISO-NE Transmission, Markets and Services Tariff. That section requires ISO-NE to conduct an evaluation of the impacts of any new transmission facility rated 69 kV or above on the stability, reliability or operating characteristics of the network. On October 13, 2010, Northern Pass filed an application with ISO-NE for review of the NPT Line under Section I.3.9.[26] To the extent

[26] The NPT Line will be evaluated through the ISO-NE review process that is appropriate for this project. As the Commission observed, the NPT Line "would not be reviewed under ISO-NE's entire regional system planning review process that other reliability projects which have the potential cost-sharing concerns are subject to. Rather, as the May 22 Order states this Project will undergo ISO-NE's section I.3.9 reliability review process to ensure that it does not cause

that ISO-NE determines that other AC upgrades are required to satisfy Section I.3.9, the TSA provides that HQ Hydro Renewable will be responsible for the costs thereof through the formula rate. Other transmission customers under the ISO-NE OATT will not be responsible for the cost of any new or upgraded transmission facilities that need to be constructed in order to interconnect the NPT Line to the New England transmission system, unless and to the extent ISO-NE determines that all or any portion of such costs are eligible for inclusion in regional rates, and HQ Hydro Renewable chooses not to fund those upgrades.[27]

On October 14, 2010, Northern Pass submitted its application to the U.S. Department of Energy for a Presidential Permit, which is required to construct and operate transmission facilities crossing an international border. Northern Pass expects to submit its permit application for siting approval with the New Hampshire Site Evaluation Committee and other federal and state regulatory approvals and permits in 2011.

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any adverse effects to system reliability." December 29 Order at P 48 (citing May 22 Order at P 63).

[27] *See* TSA, § 8.5(e). As explained in Mr. Muntz's testimony, in addition to the I.3.9 review, Northern Pass has asked ISO-NE to evaluate the NPT Line under the Overlapping Impact Test, a more rigorous standard that is similar to the one required for power to obtain status as a capacity resource in the Forward Capacity Market. Exh. No. NPT-200 at 6. Under the TSA, HQ Hydro Renewable has the option whether to pay for the construction of any additional facilities that may be required to meet this higher interconnection standard.

Construction on the NPT Line is expected to commence in 2013, and the NPT Line is expected to be in service by late 2015.[28]

E. Description of TSA

A detailed summary of the TSA is contained in Appendix A-1 to this filing.

F. Other FERC Jurisdictional Agreements

In addition to the TSA, the overall transaction will require other Commission-jurisdictional agreements to be filed with the Commission at a later time. Once the NPT Line becomes commercially operational, Northern Pass will transfer "operating control" over the line to ISO-NE pursuant to a Transmission Operating Agreement to be negotiated with ISO-NE ("TOA"). Northern Pass intends that this TOA will be based on the existing TOAs that have been negotiated with ISO-NE for other New England transmission facilities. Under the TOA, Northern Pass expects that ISO-NE will assume operational authority over the NPT Line and all transactions over the line will be scheduled in accordance with the applicable New England market rules. ISO-NE will also have final approval authority over planned line outages.

Additionally, the transaction will require that one or more interconnection agreements be entered into for the northern and southern terminals of the NPT Line. These agreements will address Northern Pass's, ISO-NE's and other parties' rights and

[28] *See* Exh. No. NPT-200 at 7 (Muntz).

obligations with respect to (1) the interconnection of the NPT Line with TransÉnergie's Québec Line at the U.S. border; (2) the interconnection of the NPT Line with PSNH's system at Deerfield substation; and (3) the NPT Line's satisfaction of the requirements of Section I.3.9 of the ISO-NE Tariff.

G. Power Purchase Agreement(s)

In the Petition for Declaratory Order, Petitioners indicated that the TSA would be associated with one or more PPAs that HQUS would enter into with NU, NSTAR Electric and other load-serving entities in New England for a period of no less than twenty years at negotiated, market-based rates, subject to state commission approval. The Petition explained that HQUS would recover the cost of transmission service it acquires under the TSA through the price for power under these PPA(s).

Although the Commission approved the use of associated long-term PPAs as described above, subsequent to the issuance of the Approval Orders, HQ Hydro Renewable has determined that it will primarily sell its power in the competitive wholesale market operated by ISO-NE. HQ Hydro Renewable has therefore agreed to bear the market risk as a power seller in order to recover the costs it incurs to purchase transmission service under the TSA.

This change in the proposed transaction should eliminate one of the principal concerns raised by intervenors in Docket No. EL09-20-000. Specifically, in the Petition

for Declaratory Order proceeding, several intervenors claimed that the proposed PPAs with load serving entities were inappropriate and should be rejected.[29] The Commission disagreed, but nonetheless HQ Hydro Renewable now intends to sell its power in the competitive U.S. bulk power markets pursuant to a market-based rate tariff. This situation reinforces the fact that the instant transaction will promote competition by putting an additional source of supply into the market.

IV. THE TSA SHOULD BE APPROVED IN ITS ENTIRETY AS A *MOBILE-SIERRA* CONTRACT

> Under the *Mobile-Sierra* doctrine, the [Commission] must presume that the rate set out in a freely negotiated . . . contract meets the "just and reasonable" requirement imposed by law. The presumption may be overcome only if FERC concludes that the contract seriously harms the public interest.

Morgan Stanley, 128 S. Ct. at 2734.[30]

Morgan Stanley and *NRG Power Marketing* clarified the law in this area by holding that the just and reasonable standard in Section 205 requires a different level of review for negotiated bilateral contracts as opposed to unilaterally filed tariffs or other agreements that are not executed by the buyers. In the former context, the Commission is

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[29] May 22 Order at PP 77-79; December 29 Order at PP 52-55.

[30] The contracts at issue in *Morgan Stanley* were power sales contracts. The TSA is a transmission contract. Both are covered equally in Section 205 and no basis exists for treating them differently for purposes of applying the *Mobile-Sierra* doctrine. Neither the Commission nor the courts have ever distinguished between the two for purposes of review under Section 205, and there is no statutory basis for doing so. *See, e.g.*, *Potomac Elec. Power Co. v. FERC*, 210 F.3d 403 (D. C. Cir. 2000) (applying the *Mobile-Sierra* doctrine to a transmission contract); *Me. Pub. Serv. Co. v. FERC*, 964 F.2d 5, 7-8 (D.C. Cir. 1992) (noting that the *Mobile-Sierra* doctrine would apply to a fixed rate transmission service contract).

required to presume that an electricity rate set by a freely negotiated contract meets the FPA's just and reasonable standard. This presumption may be overcome only if the Commission concludes that the contract seriously harms the public interest. The Supreme Court held that the "animating purpose" of the *Mobile-Sierra* doctrine is the promotion of "the stability of supply arrangements which all agree is essential to the health of the [energy] industry." The doctrine rests on the "stabilizing force of contracts." *Morgan Stanley*, 128 S. Ct. 2733 (describing contract rates as "a key source of stability"). The Court further explained that "[t]he regulatory system created by the [FPA] is premised on contractual agreements voluntarily devised by the regulated companies; it contemplates abrogation of these agreements only in circumstances of unequivocal public necessity."[31] The Court explained that the Commission can modify executed contracts "only when the mutually agreed upon contract rate seriously harms the consuming public."[32]

The Supreme Court also held in *Morgan Stanley* that this rule applies to the Commission's initial review of an executed contract as well as its review of later modifications thereto. The Court addressed the question of whether the *Mobile-Sierra* presumption "appl[ies] only when FERC has had an initial opportunity to review a

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[31] *See NRG Power Mktg., LLC*, 130 S. Ct. at 699 (citing *Permian Basin Area Rate Cases*, 390 U.S. 747, 822 (1968)).

[32] *Id.*

contract rate without the presumption."[33] The Court held that the presumption applies with equal force to the Commission's initial and subsequent reviews of a contract.[34] In other words, the *Mobile-Sierra* presumption applies as of the parties' execution of a contract and accompanies the contract in its initial filing with the Commission and in any subsequent Commission reviews of the contract.

In *NRG Power Marketing*, the Court further held that the *Mobile-Sierra* presumption is not limited to the contracting parties, but applies to third parties as well.[35] Of course, in this case, there are no "third parties" that are directly affected by the costs of transmission service price under the TSA; third parties can be affected indirectly only by the price at which power transmitted over the NPT Line will be sold by HQ Hydro Renewable, which will be determined by the competitive power market.

The Commission has acknowledged that *Morgan Stanley* requires it to assume that the parties to an executed agreement intend that the contract will receive *Mobile-Sierra* protection, unless the parties expressly provide otherwise. In an Order issued in Docket No. RM05-35-000 terminating the rulemaking in that docket, the Commission stated:

> There is no longer a need for a rulemaking regarding the default standard of review, as the Supreme Court has addressed the law in this area. Since issuance of the NOPR, the United States Supreme Court has addressed the Mobile-

[33] *Morgan Stanley*, 128 S. Ct. at 2737.

[34] *Id.* at 2745.

[35] *NRG Power Mktg.*, 130 S. Ct. at 700.

> Sierra doctrine in Morgan Stanley. The Court held that the Mobile-Sierra doctrine is a presumption that rates initially set in a freely negotiated contract meet the statutory just and reasonable requirement of the FPA. The Court explained that "parties could contract out of the Mobile-Sierra presumption by specifying in their contracts that a new rate filed with the Commission would supersede the contract rate," but otherwise "the Mobile-Sierra presumption remains the default rule."[36]

In this case, no reasonable question exists concerning the parties' intent to apply the *Mobile-Sierra* presumption. There is no language in the TSA that indicates any intent to "contract out of" this presumption, and in Section 20.2 thereof, the parties have made clear that any changes to the TSA by the parties must be by mutual agreement and that the *Mobile-Sierra* public interest standard as described in *Morgan Stanley* shall apply to any Commission-imposed modifications or proposed third party amendments:

> Other Modifications. The Parties specifically intend and acknowledge and agree that, except as otherwise expressly provided in this Agreement, (a) this Agreement shall not be subject to amendment or other modification, absent the written agreement of both Parties and (b) neither Party shall be permitted to make a filing with FERC under any provision of the Federal Power Act or the regulations promulgated thereunder that seeks to amend or otherwise modify, or requests FERC to amend or otherwise modify, any provision of this Agreement at any time during the Term, except to implement an amendment or other modification to this Agreement that has been reduced to writing and signed by both Parties. In addition, to the extent any third party, or FERC acting *sua sponte* seeks to amend or otherwise modify, or requests FERC to amend or otherwise modify, any

[36] *Standard of Review for Modifications to Jurisdictional Agreements*, 125 FERC ¶ 61,310 at P 4 (2008) (citing *Morgan Stanley*, supra).

> provision of this Agreement, the standard of review for any proposed amendment or other modification shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp*., 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), and as further defined in *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 128 S. Ct. 2733 (2008) and *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 130 S. Ct. 693 (2010).

The TSA is a quintessential *Mobile-Sierra* contract. First, the contract was negotiated by sophisticated entities. The parties to the TSA are newly-created subsidiaries of sophisticated public utility enterprises with substantial electric businesses, and all are longstanding market participants in New England. The buyer and seller are not affiliated, and they carefully negotiated this agreement as a voluntary, arms-length commercial arrangement in which they would share in the risks associated with the construction and operation of a large and complex transmission project.

These sophisticated parties voluntarily chose to negotiate a unique arrangement between themselves rather than rely on provisions of the ISO-NE OATT to accomplish an expansion of the transmission system in a more traditional manner. Hydro-Québec, for example, had the option of submitting a request to ISO-NE for 1,200 MW of firm transmission service under the ISO-NE OATT, which would have precipitated application of a specific set of tariff rules and requirements resulting in consideration of Hydro-Québec's proposal under the New England regional planning process and, if

approved in the planning process, allocation of the costs of the project to New England load under the filed cost allocation rules. Instead of using this Commission-approved process, which would have raised complex planning and cost allocation issues that could have delayed the project or prevented it from being completed, Hydro-Québec chose to negotiate a bilateral transaction with NU and NSTAR that would result in a participant-funded elective transmission upgrade as defined in the ISO-NE OATT. Because of this choice, the transaction shifts responsibility for the cost of the NPT Line from New England load to HQ Hydro Renewable, and for this reason avoids imposing incremental transmission expansion costs on the consuming public.

The TSA is the product of extensive arm's length negotiation by the parties. The parties engaged in months of negotiations in order to achieve a mutually acceptable allocation of risks and responsibilities in connection with this significant investment by Northern Pass. The product of these negotiations is a unique and comprehensive 185-page contract reflecting the fact that HQ Hydro Renewable will be responsible for approximately $1.1 billion in construction costs over a 40-year term (plus costs of capital expenditures and return after commercial operation and operation and maintenance expenses, administrative and general expenses, tax expense, and other expenses associated with the NPT Line). The TSA therefore represents precisely the kind of negotiated contractual arrangement that the Supreme Court found to be essential to the health and the effective functioning of the electric industry.

Finally, the TSA promotes the public interest by providing a number of important benefits to New England consumers without requiring them to bear any upfront costs for a new transmission line that will substantially increase the region's energy import capability. The NPT Line will provide New England with access to 1,200 MW of low carbon, predominantly hydro-electric power. This will displace fossil-fired generation in New England. Northern Pass estimates that greenhouse gas emissions associated with producing electricity will be reduced by up to five million tons of carbon dioxide per year, which is equivalent to the annual emissions of nearly 900,000 cars.[37] These emission reductions will help the New England states meet New England's Regional Greenhouse Gas Initiative ("RGGI") requirements.

The TSA will also expand power supply in the competitive market, which (all else being equal) should reduce wholesale energy prices paid by consumers. The attached study by CRA shows that the NPT Line will reduce congestion between Québec and ISO-NE by allowing more low-cost energy to be imported into New England that will displace higher cost generation. The hydro-electric-based energy that can be imported under the TSA will also diversify New England's power supply, which ISO-NE believes may be becoming overly dependent on natural gas generation. This imported energy will reduce

[37] *See* Exh. No. NPT-200 at 20 (Muntz).

the regional reliance on natural gas for electric power generation and free up available supplies of natural gas for other uses.[38]

Based on the decisions of the Supreme Court in *Morgan Stanley* and *NRG Power Marketing*, it is clear that the Court was referring to voluntary, executed contracts like the TSA, and intended that the parties to such contracts have the flexibility to negotiate unique arrangements because such negotiated agreements would benefit the public interest. That finding applies fully to this agreement, and the TSA should therefore be approved in its entirety.

V. IF THE COMMISSION DOES NOT APPROVE THE TSA AS A *MOBILE-SIERRA* CONTRACT, THE COMMISSION SHOULD FIND THE TSA TO BE JUST AND REASONABLE UNDER A TRADITIONAL ANALYSIS OF THIS COST-BASED CONTRACT

A. Formula Rate

Under the TSA, Northern Pass will use a formula rate to calculate HQ Hydro Renewable's payment obligations for transmission service over the NPT Line. As explained in the attached testimony of Paula Taupier, the formula in the TSA is a forward-looking formula rate that calculates costs on a prospective basis and then trues up such projected costs to actual costs in order to permit Northern Pass to recover the annual revenue requirement associated with the NPT Line and AC Upgrade costs. The formula rate recovers a return on Northern Pass's investment in the NPT Line plus

[38] ISO-NE 2010 Regional System Plan, §§ 1.1.4.1, 7.5.6, 13. *See also* Exh. No. NPT-200 at 21 (Muntz).

associated income taxes, depreciation expense, operation and maintenance expenses, administrative and general expenses, municipal tax expense, and other expenses associated with the NPT Line (including AC Upgrade costs).[39] The formula provides for Northern Pass to project the revenue requirement for each calendar year and charge the resulting rates in that calendar year.[40] A true-up amount based on the difference between the forecasted and actual revenue requirement would be calculated the following year, and a surcharge or refund, as appropriate, including interest calculated pursuant to 18 C.F.R. § 35.19a(a),[41] would be included in a single lump sum on the same date on which either (1) Northern Pass is required to submit the first invoice to be delivered after the receipt by HQ Hydro Renewable (in the case of a refund) or (2) HQ Hydro Renewable is required to pay the first invoice to be delivered after the receipt by HQ Hydro Renewable (in the case of a surcharge).

The formula rate in the TSA is based on formula rates the Commission has accepted previously. It reflects Commission-approved ratemaking methodologies and contains sufficient specificity to operate without discretion or arbitrary deviation from the stated terms in its implementation by Northern Pass. The formula should be accepted as just and reasonable.

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[39] *See* Exh. No. NPT-400 at 3 (Taupier).

[40] TSA, § 14.1(d).

[41] *Id.*

B. Audits of Northern Pass Costs and Prudence

The TSA includes mechanisms whereby Northern Pass is obligated to provide forecasts of its costs to HQ Hydro Renewable for review, comment and approval before costs are incurred in order to minimize disagreements between the parties. HQ Hydro Renewable will be represented on a management committee that will have the right, among other things, to approve construction budgets for the NPT Line.[42] During the construction phase, Northern Pass will be required to update the construction budget and schedule on a quarterly basis. The management committee may approve the construction budget and schedule in whole or in part, in which event they will not be subject to challenge.[43] Similar provisions require Northern Pass to submit budgets of O&M costs and capital expenditures during commercial operation so that the management committee can review and approve them.[44]

The TSA also requires Northern Pass to provide cost support information for each component of the formula rate on an annual basis so that HQ Hydro Renewable can audit Northern Pass's compliance with the formula rate.[45] HQ Hydro Renewable has the contractual right to request additional information relevant to the calculation of charges

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[42] Exh. No. NPT-400 at 9-10 (Taupier).

[43] TSA, § 5.2.2. During the Construction Phase, if HQ Hydro Renewable does not approve the construction budget and schedule, its only remedy is termination of the TSA.

[44] *Id.*, § 6.3.

[45] *See id.*, § 14.2(a).

so that it can engage in meaningful audits of Northern Pass's costs.[46] HQ Hydro Renewable retains the right to file challenges at the Commission if Northern Pass is not complying with the formula rate.[47]

All costs that flow through the formula rate must be prudently incurred and are subject to a FERC imprudence challenge by HQ Hydro Renewable unless HQ Hydro Renewable or an arbitrator has approved the costs in advance or unless they are deemed approved, as, for example, under § 5.2.2(b). *See* TSA, §§ 8.1.4(b) and (c) (stating that HQ Hydro Renewable will have the right to challenge the prudency of any costs or expenses that Northern Pass seeks to recover under the TSA except those previously approved or deemed approved). The TSA provides that prudence challenges will be handled pursuant to the Commission's normal processes for such challenges, including the then applicable prudence standard and the normal burden of proof.[48]

C. ROE

The TSA formula rate uses a negotiated, initial ROE of 12.56 percent during the construction period to calculate AFUDC, which is well below the high end of the zone of reasonableness established by the DCF study presented in the testimony of Dr. William

[46] *Id.*, §14.2(b).

[47] *Id.*, § 8.1.5.

[48] *Id.*, § 8.1.4(b).

Avera.[49] As discussed in Section VII below, to the extent necessary, Northern Pass is seeking Commission approval under Order No. 679 for an incentive-based ROE at this level. The attached testimony of Messrs. Auseré and Lubbock demonstrates that the proposed ROE reflects the unique risks borne by the seller under the TSA, which include reliance on a single party for payment of the seller's investment for forty years and contractual risks created by the various terms of the TSA and related guarantees by the buyer's parent company.

Dr. Avera's analysis is based on a DCF analysis of both a national and a regional proxy group. Consistent with the Commission's two recent orders in *Atlantic Path 15, LLC*, 133 FERC ¶ 61,153 at P 13 (2010) ("*Atlantic Path 15*") and *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 at P 60 (2010) ("*PATH*"), in which the Commission clarified that it will not mandate a filing party to use a proxy group composed of companies in the same geographic region,[50] Dr. Avera examined a national proxy group of companies with comparable risks to those faced by Northern Pass. Dr. Avera's national proxy group is composed of other utilities included by Value Line in its Electric Utilities Industry groups with: (1) S&P corporate credit ratings between "BBB-"

[49] Exh. No. NPT-600 at 85-86 (Avera). Northern Pass submits Dr. Avera's workpapers containing the calculations and data underlying the updated ROE analyses. In addition, Northern Pass provides an Excel workbook containing Dr. Avera's analyses and exhibits in electronic format with formulas intact.

[50] In the two cited orders, the Commission explained that while "geographic proximity may be a relevant factor in identifying companies with comparable risks, it is not the sole basis for inclusion of companies in a proxy group."

and "BBB+"; (2) a Value Line Safety Rank of "2" or "3"; (3) a Value Line Financial Strength Rating of "B" to "B++"; and (4) published data from Value Line and IBES.[51] Dr. Avera excluded those companies that are currently involved in a merger or a major acquisition, including NU and NSTAR, and companies that fail the Commission's test of whether the DCF results fail fundamental tests of economic logic. Dr. Avera employs the Commission's traditional application of the DCF method for electric utilities.[52] Dr. Avera's national proxy group consists of 24 companies that are predominantly electric utilities.[53] For the national proxy group, Dr. Avera determines a zone of reasonableness ranging from 7.7 percent to 16.4 percent, with the midpoint at 12.1 percent and the median at 10.4 percent.[54]

Based upon the Commission's precedents prior to *Atlantic 15* and *PATH*,[55] Dr. Avera also looked at a regional proxy group consisting of transmission-owning members in ISO-NE, PJM Interconnection, LLC ("PJM"), and the New York Independent System Operator, Inc. ("NYISO") with publicly traded stock. Again, Dr. Avera excluded utilities that are currently involved in a major merger or acquisition. After removing DCF results

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[51] Exh. No. NPT-600 at 30-31 (Avera).

[52] *Id.* at 5.

[53] *Id.* at 30; Exh. No. NPT-602.

[54] Exh. No. NPT-600 at 45 (Avera); Exh. No. NPT-603.

[55] *See, e.g.*, *Bangor Hydro-Elec. Co. et al.*, Opinion No. 489, 117 FERC ¶ 61,129 at P 3 (2006), *order on reh'g*, 122 FERC ¶ 61,265 (2008); *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 at P 95 (2008), *order on rehearing*, 133 FERC ¶ 61,152 at P 60 (2010); *Va. Elec. Power Co.*, 123 FERC ¶ 61,098 at P 60 (2008).

outside of a computed range of ROE outcomes that fail fundamental tests of economic logic as previously defined by the Commission, Dr. Avera determines a zone of reasonableness for the regional proxy group of 7.7 percent to 16.4 percent, with the midpoint at 12.1 percent and the median at 10.2 percent.[56]

Dr. Avera also applied the Commission's bond ratings screen to the regional proxy group, which reduced the regional proxy group to three companies. For this proxy group, Dr. Avera identifies a zone of reasonableness of 8.6 percent to 16.4 percent, with the midpoint at 12.5 and the median at 11.2 percent.[57]

Because an incentive ROE from the upper end of the reasonable DCF range is warranted for Northern Pass, Dr. Avera testifies that there was no reason to determine a point estimate from within the zone of reasonableness by reference to either the midpoint or median.[58] Dr. Avera did note, however, that he would not support or recommend sole reliance on the median to evaluate the ROE for Northern Pass because the median values for the proxy groups of electric utilities produced using the Commission's methodology fall consistently below other measures of central tendency.[59]

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[56] Exh. No. NPT-600 at 45; Exh. No. NPT-605.

[57] Exh. No. NPT-600 at 45; Exh. No. NPT-607.

[58] Exh. No. NPT-600 at 45-54.

[59] *Id.* at 47-51.

The parties' 12.56 percent ROE during the construction period is 384 basis points below the 16.4 percent upper end of the zone of reasonableness for the regional and national proxy groups, and is consistent with recent incentive ROEs that the Commission granted in other proceedings.[60] If the Commission finds that it is necessary to evaluate the proposed ROE based upon a reference point within the zone of reasonableness despite Dr. Avera's contrary testimony, the 12.56 percent equals a base ROE of 10.4 percent (i.e., the median of the national proxy group), plus an adder of 50 basis points for RTO participation, and a new transmission incentive adder of 164 basis points. This does not include an additional adder that would reflect the fact that Northern Pass will use advanced transmission technologies in the construction of the NPT Line as discussed by Mr. Muntz in his testimony (Exh. No. NPT-200 at 32-38), for which the Commission has granted incentive adders in prior cases.[61] The incentive adder would be 146 basis points if the base ROE is calculated by averaging the median from the three proxy groups, or only 46 basis points (less than the 50 basis points allowed for RTO membership) if the base ROE equals the 12.1 percent midpoint in the national proxy group.

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[60] *See, e.g.*, *Ne. Utils. Serv. Co. and Nat'l Grid USA*, 125 FERC ¶ 61,183 (2008) (granting an ROE of 12.89 percent for the New England East-West Solution, in addition to 100 percent CWIP and abandoned plant cost recovery); *Ne. Utils. Serv. Co.*, 124 FERC ¶ 61,044 (2008), *reh'g denied*, 126 FERC ¶ 61,052 (2009) (granting an ROE of 12.64 percent for the Middletown-to-Norwalk transmission project).

[61] *See, e.g.*, *W. Grid Dev., LLC*, 130 FERC ¶ 61,056 at P 98 (2010) (conditionally granting a 45 basis point advanced transmission technology adder); *Ne. Utils. Serv. Co.*, 124 FERC ¶ 61,044 at P 91 (2008), *reh'g denied*, 126 FERC ¶ 61,052 (2009) (granting a 50 basis point advanced transmission technology adder for the underground portion of the Middletown-to-Norwalk transmission project); *The United Illuminating Co.*, 119 FERC ¶ 61,182 at P 73 (2007), *reh'g denied*, 126 FERC ¶ 61,043 (2009) (same).

In his testimony, Dr. Avera explains why he believes the midpoint is the more appropriate number to use should a single point estimate be required.[62] However, in order to eliminate any dispute in this proceeding over whether the midpoint or median is the appropriate starting point for establishing the correct requested ROE, Northern Pass believes that the Commission should grant an ROE of 12.56 percent on the basis that it is well below the high end of the zone of reasonableness and without reference to any particular adder amount. It should be noted that the TSA does not provide for inclusion of CWIP in rate base during the construction period, which distinguishes this transaction from most of the other transmission projects that have received incentive rate treatment under Order No. 679. In other cases, the Commission has reduced the ROE in circumstances where the applicant requested 100 percent CWIP treatment during the construction period.

D. HQ Hydro Renewable Will Receive Firm Transmission Service

In exchange for its transmission service payments, HQ Hydro Renewable will receive 1,200 MW of firm transmission service. This firm transmission service will be subject to curtailment or interruption only in certain defined circumstances that are consistent with the provision of firm service over radial DC and AC lines: a Force Majeure event; scheduled maintenance; outages or reductions in the use of transmission lines other than the NPT Line; decisions of TransÉnergie or conditions on the electric

[62] Exh. No. NPT-600 at 48-50 (Avera).

system in the Province of Québec, including the unavailability of the Québec Line; and decisions of ISO-NE to reduce or suspend scheduling rights over the NPT Line due to reliability issues.[63] Northern Pass is responsible for any outages caused by its failure to follow good utility practice or otherwise comply with the TSA.

To the extent that (i) the design, engineering, construction or operation of the NPT Line results in incidental capacity in the line above 1,200 MW (or any lesser amount established upon commissioning) and (ii) ISO-NE permits the scheduling of transmission service using such incidental capacity during any hour (or other ISO-NE scheduling period), HQ Hydro Renewable may schedule non-firm transmission using such incidental capacity.[64]

E. Sales of Unused Capacity

Article 10 of the TSA provides that, if the transmission capacity of the NPT Line exceeds HQ Hydro Renewable's needs, HQ Hydro Renewable will offer to sell such unused capacity in accordance with applicable law, including the terms and conditions of FERC Order No. 890. TSA, § 10.1. Further, Article 10 provides that the parties will jointly contract with an independent, non-affiliated third party for use of an open access same-time information system ("OASIS") site and to serve as the OASIS administrator. TSA § 10.3. The parties' proposal with respect to the resale of transmission service is

[63] TSA, § 7.3(b).

[64] *Id.* § 7.1.2.

consistent with the Commission's Approval Orders in that it "mak[es] unused capacity available to third parties pursuant to Order No. 890."[65] In Order No. 890,[66] the Commission found that the creation of a competitive market for secondary transmission capacity would result in existing transmission facilities being used more efficiently[67] and would "send[] more accurate price signals to identify the appropriate location for construction of new transmission facilities . . . ."[68] The Commission also adopted a number of measures in Order No. 890 to enhance its oversight and monitoring of the reformed secondary market for transmission capacity, including a requirement that all sales or reassignments of capacity be conducted through, or otherwise posted on, the transmission provider's OASIS, on or before the date reassigned service commences.[69] Article 10 of the TSA provides for the use of OASIS for the sale of unused transmission capacity, consistent with the requirements of Order No. 890.

F. Depreciation Rates

Under the TSA, the parties have agreed that, for ratemaking purposes, the depreciable life of the original NPT Line assets will be 40 years, and any capital additions

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[65] May 22 Order at P 55.

[66] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 ("Order No. 890"), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007) ("Order No. 890-A"), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *clarified*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[67] *See* Order No. 890-A at P 388.

[68] Order No. 890 at P 808.

[69] *Id.* at P 815.

will be depreciated at the lesser of their economic life and the remaining term of the TSA as of the date placed in service.[70] Northern Pass submits that it is appropriate and consistent with Commission precedent for the parties to agree to this depreciation schedule without having to provide a depreciation study.[71] In addition, the TSA provides that if there is another use of the NPT Line after the end of the term of the TSA, Northern Pass will reimburse HQ Hydro Renewable for a *pro rata* portion of the costs and expenses of each capital addition that has an expected useful life beyond the end of the term of the TSA.[72]

VI. ALTERNATIVE REQUEST FOR COMMISSION APPROVAL OF THREE TSA RATE PROVISIONS UNDER ORDER NO. 679

To the extent that the Commission cannot approve the TSA in its entirety under the *Mobile-Sierra* doctrine and requires certain TSA rate provisions to be justified under the incentive ratemaking criteria of Order No. 679, Northern Pass hereby provides information and materials pursuant to Order No. 679 in support of three rate provisions that may be characterized as rate incentives: (1) the ROE of 12.56 percent for purposes of accruing AFUDC during the construction period, and upon commercial operation, an

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[70] TSA, § 8.2.

[71] With respect to other new transmission projects, the Commission has accepted the applicant's proposed depreciation schedule without requiring the submission of a depreciation study. *See, e.g.*, *W. Area Power Admin.*, 99 FERC ¶ 61,306 (2002) (accepting the applicant's proposed thirty-year depreciation schedule without requiring a depreciation study); *Trans Bay Cable LLC*, 112 FERC ¶ 61,095 (2005) (same).

[72] TSA, § 9.2.

ROE equal to the base ROE under the ISO-NE OATT (currently 11.14 percent) plus the lesser of an adder of 142 basis points or an amount that would not cause the total ROE to exceed the applicable zone of reasonableness; (2) the termination rights provisions and the parties' associated cost responsibility thereunder; and (3) the establishment of a regulatory asset to recover certain pre-commercial operation costs incurred by Northern Pass not included in FERC Account No. 107 as CWIP.

Under Order No. 679, an applicant requesting incentive rate treatment must provide a detailed explanation of how the proposed rate treatment complies with Section 219 of the FPA, including a demonstration that the incentives are just and reasonable and not unduly discriminatory or preferential. To do this, the applicant must demonstrate that: (1) the facilities for which it seeks incentives satisfy the requirements of FPA Section 219 – i.e., they either ensure reliability or reduce the cost of delivered power by reducing congestion; (2) the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project – i.e., the incentives meet the nexus test; and (3) the resulting rates are just and reasonable.[73] As detailed below, the incentive provisions agreed to by the parties under the TSA meet all three elements of this test.

[73] *See* 18 C.F.R. § 35.35(d).

A. The NPT Line Satisfies the Requirements of FPA Section 219

Order No. 679 provides that a public utility may make an FPA Section 205 filing to obtain incentive rate treatments for transmission infrastructure investment that satisfies the requirements of FPA Section 219 – namely, that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[74]

In Order No. 679, the Commission created a rebuttable presumption that this requirement is satisfied for projects that either result from a fair and open regional planning process or that have received construction approval from an appropriate state commission or state siting authority.[75] The Commission also indicated that it will consider incentive requests for projects that are still undergoing consideration in a regional transmission planning process but may make any requested incentive rate treatment contingent on the project being approved under the regional transmission planning process.[76] Further, the Commission has explained that a project that does not qualify for the rebuttable presumption may nevertheless satisfy the FPA Section 219 standards if the applicant presents a factual record supporting a finding that the project is needed to maintain reliability or reduce congestion.[77] The Commission clarified that to

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[74] *See* 18 C.F.R. § 35.35(i).

[75] Order No. 679 at PP 57-58.

[76] *Id.*

[77] *Id*. at P 57.

meet this requirement, the applicant "may present detailed studies, engineering affidavits, or state siting approvals demonstrating that the FPA section 219 criteria are met."[78]

1. The NPT Line Meets the Requirements of Section 219

As part of this filing, Northern Pass submits evidence in the form of studies by independent experts demonstrating that the NPT Line will reduce the cost of delivered power into the ISO-NE markets by reducing transmission congestion. Further, as discussed in the attached Muntz testimony, the NPT Line will have positive effects on the reliability of the bulk power transmission system and will produce environmental and economic benefits.

a. The NPT Line will reduce the price of delivered power by reducing transmission congestion

Northern Pass retained CRA, an economic consulting firm, to provide an independent assessment of the congestion reduction benefits of the NPT Line. CRA's assessment was based on modeling of the ISO-NE system with and without the NPT Line in service, and quantified the effect of adding the line on Locational Marginal Price ("LMPs") throughout New England.

CRA used the General Electric Multi-Area Production Simulation Model ("GE MAPS"), a detailed economic dispatch and production-costing model for electricity

[78] *W. Grid Dev., LLC*, 130 FERC ¶ 61,056 at P 57 (2010) (citing *Duquesne Light Co.*, 118 FERC ¶ 61,087 at P 68 (2007)); *see also Green Power Express LP*, 127 FERC ¶ 61,031 at P 41 (2009).

networks that was originally developed by General Electric and is currently used by over twenty major utilities and RTOs in the United States. CRA used this model to estimate the market clearing prices and the associated dispatch of generating units throughout the ISO-NE system under scenarios both with and without the NPT Line.

Based on these simulation studies, CRA concludes that the NPT Line will reduce congestion between Québec and ISO-NE by allowing lower cost power from Québec to be imported to ISO-NE, thereby displacing more expensive generation on the ISO-NE system. Further, the NPT Line will allow more energy imported from Québec to be delivered during peak hours when marginal generation costs and market-clearing prices are highest. *See* Exh. No. NPT-700 at 2 (CRA Report) ("Without the NPT Line, existing ties are expected to be fully utilized in 99.8 percent of peak hours. The capacity of the NPT Line allows energy delivered in other, lower-priced hours, or delivered to lower-priced locations in New York and Ontario, to be reallocated to deliveries in New England during these peak hours, when (and where) power is most valuable.").[79] CRA estimates that with the NPT Line in service, there will be a cost reduction to wholesale load customers of $1.58/MWh or $206 million in 2015 (assuming the project is in service in

[79] In addition to reduced congestion and lower wholesale power prices in New England, the CRA Report also explains that the NPT Line will provide a number of other important benefits, including (i) adding to ISO-NE reserve margin for several years and, based on current demand forecasts, delaying the need for new capacity by four to five years; and (ii) providing fuel supply benefits by reducing dependence on natural gas. *See* Exh. No. NPT-700 at 3.

2015) and $2.30/MWh or $327 million in 2024, and that the cost savings should be passed onto retail customers.[80]

b. Reliability Benefits

The NPT Line will also help ensure the reliability of the bulk power transmission system in New England by creating a new transmission path for the delivery of power from hydro-electric generation resources located in Québec to consumers in New England.[81] As explained by Mr. Muntz, the addition of the 1,200 MW international NPT Line and Québec Line will provide the ISO-NE system with an added degree of reliability in that New England will now have another 1,200 MW source of power on which to rely.[82] Mr. Muntz explains that the NPT Line will perform electrically as if a new generation source had been constructed within the ISO-NE system. Further, the

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[80] *Id.* at 1.

[81] In addition, the NPT Line will be vetted for its reliability impacts through the ISO-NE planning process. The NPT Line is a participant-funded transmission project and its costs will be borne by one customer rather than being broadly allocated on a regional basis. In the Approval Orders, the Commission recognized that because the NPT Line will not raise cost-sharing concerns, it is not appropriate for the project to be reviewed under ISO-NE's normal system planning review that other reliability projects must undergo. December 29 Order at P 48; May 22 Order at P 63. Instead, as the Commission noted, the NPT Line will undergo ISO-NE's section I.3.9 reliability review to ensure that it does not cause adverse effects to system reliability. *Id*. In his testimony, Mr. Muntz describes in detail the Section I.3.9 process which the NPT Line will undergo, including various upgrades and modifications that ISO-NE may require in order to ensure the safe and reliable interconnection of the project to New England's transmission system. Exh. No. NPT-200 at 12-13 (Muntz). As part of ISO-NE's Section I.3.9 process, ISO-NE will ensure that the construction and interconnection of a new transmission path between Québec and New England will not have an adverse effect on system operation or reliability.

[82] Exh. No. NPT-200 at 18-19 (Muntz).

construction of the 40-mile AC Line from Franklin to Deerfield will extend the existing 345-kV bulk power system further north, which may provide an attractive "jump off" point for additional reliability-based 345 kV upgrades in the future as loads increase.[83]

c. Environmental and Economic Benefits

New England currently faces significant energy and environmental challenges, and its electricity prices are among the highest in the nation. Additionally, new environmental requirements for low carbon, renewable resources will require a significant increase in renewable generation and a change to the region's generation mix.[84] However, even with significant contributions from energy efficiency programs and new, local renewable generation, New England will face challenges in meeting its future environmental requirements.[85] Importing hydro-electric power from Canada holds the potential to help meet New England's energy demands and environmental requirements.[86]

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[83] *Id.* at 19. Mr. Muntz explains that some of the potential reliability projects that are enabled by the 40-mile AC Line "include the addition of autotransformers [at the new Franklin substation] to enhance reliability in that region and further expansion of the 345-kV system to points north or west to meet future reliability needs in either New Hampshire or Vermont." *Id*. at 19.

[84] Exhibit No. NPT-200 at 8 (Muntz).

[85] *Id.* at 8.

[86] *Id*.

First, low carbon hydro-electric power from Québec will help reduce greenhouse gas emissions and meet the New England RGGI requirements.[87] To the extent that hydro-electric power purchased from Québec displaces gas-fired generation in New England, greenhouse gas emissions associated with the production of electricity will be reduced by up to 5 million tons of carbon dioxide per year during the term of the transaction, which is equivalent to the annual emissions of nearly 900,000 cars.[88]

Second, low carbon, hydro-electric energy transmitted over the NPT Line will provide fuel diversity benefits that ISO-NE has determined to be essential at this time.[89]

Finally, the NPT Line will produce significant economic benefits to New Hampshire's economy and its residents, including creating 1,100 to 1,300 jobs annually in New Hampshire during the development and construction phase of the project (from 2013 to 2015), increasing local tax bases, and helping the state's economy by providing low cost, clean energy.[90]

B. There is a Nexus Between the Incentives and Northern Pass's Investment in the NPT Line

Under Order No. 679, an applicant requesting rate incentives must demonstrate that there is a nexus between the incentive sought and the investment being made. In

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[87] *Id.*

[88] *Id.* at 20.

[89] *Id.* at 21-22; *see also* ISO-NE 2010 Regional System Plan, §§ 1.1.41, 7.5.6, 13.

[90] *See* Exh. No. NPT-200 at 22 (Muntz); Exh. No. NPT-205 at 1-6 (October 2010 "Preliminary Economic and Fiscal Impacts of the Proposed Northern Pass Transmission Project").

Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[91]

In evaluating whether the requested incentives are tailored to address the demonstrable risks or challenges faced by the applicant, the Commission considers the question of whether a project is "routine." The Commission has explained that projects that are non-routine by definition face inherent risks and challenges and/or provide benefits that are worthy of incentives. In several cases, the Commission held that an applicant who has demonstrated a project is non-routine also meets the nexus requirement for an ROE incentive.[92] In evaluating whether a project is routine, the Commission has stated that it will consider all relevant factors, including:

> (i) the scope of the project (*e.g.*, dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (ii) the effect of the project (*e.g.*, improving reliability or reducing congestion costs); and (iii) the challenges or risks faced by the project (*e.g.*, siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).[93]

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[91] Order No. 679-A at P 40; *Xcel Energy Servs., Inc.*, 121 FERC ¶ 61,284 at P 54 (2007) (The Commission will examine "the total package of incentives being sought, the interrelationship between any incentives, and how any requested incentives address the risks and challenges faced by the project.").

[92] *See, e.g.*, *Baltimore Gas and Elec. Co.*, 120 FERC ¶ 61,084 at P 53 (2007).

[93] *Id.* at P 52. The Commission has explained that "these are only examples of evidence that can help inform the Commission on the question of whether a project is routine" and that this is not

The NPT Line is a non-routine, large scale international transmission project that will produce broad regional benefits and will be subject to extensive federal and state level reviews. As such, the NPT Line faces significant risks and challenges.

1. Scope

The NPT Line is a large-scale transmission project and is readily distinguishable from other transmission projects or upgrades that are constructed in the ordinary course of a utility's transmission service obligation to provide safe and reliable service to its customers. In dollar terms, the NPT Line's total cost of about $1.1 billion places it among the largest transmission projects in New England. Mr. Muntz explains that the NPT Line will be the largest transmission project in New Hampshire since the existing HVDC transmission tie was constructed in the 1980s. It will impact 31 cities and towns and will take six to seven years (counting from the beginning of the development process in 2009) to design, plan, permit, and build.[94]

From an electrical perspective, the NPT Line is large by any standard. The construction of this project will vastly expand the New England transmission system's ability to transfer power from low carbon, predominantly hydro-electric power to load

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"a new formulaic checklist that must be met by every applicant for every proposed incentive or project." *Id.* at P 52 n.53. *See also Great River Energy*, 130 FERC ¶ 61,001 at P 31 (2010); *ITC Great Plains, LLC*, 126 FERC ¶ 61,223 at P 52 (2009).

[94] Exh. No. NPT-200 at 23 (Muntz).

and will enhance the performance and reliability of the existing transmission system in New England.[95]

The NPT Line is also significant in terms of both its scale and its costs. The NPT Line will require construction of approximately 180 miles of new extra high voltage transmission lines in the United States (140 miles of new 300 kV HVDC transmission lines and 40 miles of 345 kV AC transmission lines) and may also require improvements to the existing AC transmission system as a result of the I.3.9 process.[96]

For purposes of demonstrating the non-routine nature of the NPT Line, NU's share of the project of $820 million is a major transmission investment for NU. For purposes of comparison, an average transmission upgrade for NU for the period 2006 through 2009 had a cost of approximately $4 million.[97] NSTAR's share of the NPT Line of $275 million is equally significant in comparison to an average transmission upgrade for NSTAR for the period 2006 through 2009, which had a cost of $5.3 million.[98]

Finally, the NPT Line is not a typical reliability utility project,[99] but a large-scale regional transmission project to enhance the capability of the New England transmission

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[95] *See id.* at 18-19.

[96] *Id.* at 4-5.

[97] Exh. No. NPT-300 at 10-11 (Auseré/Lubbock); *see also* Exh. No. NPT-301.

[98] *Id*.

[99] *See* Order No. 679-A at P 23; *Pub. Serv. Elec. and Gas Co.*, 131 FERC ¶ 61,028 at P 18 (2010) (stating that "the most compelling case for incentives are new projects that present special

system to advance regional and national energy policy by allowing for the delivery of substantial quantities of hydro-electric power from Québec, Canada.[100]

2. Effect

As discussed above, the positive effect of the NPT Line is undeniable – it will make available up to 1,200 MW of previously unavailable power from Québec, thus lowering electricity prices in New England, improving reliability, and promoting important environmental goals, as outlined above and detailed in the CRA Report and the Muntz testimony.

3. The NPT Line Faces Significant Risks and Challenges

The NPT Line is of a size and complexity that represents a significant challenge.

a. Siting Challenges

As described by Mr. Muntz, the NPT Line faces a unique level of siting and permitting risks. Construction of the NPT Line is subject to approval by federal and state authorities.[101] The state siting process will consider numerous factors for each project, including alternatives to each of the projects, such as route alternatives, potential environmental and social issues, engineering design, and costs.

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risks or challenges, not routine investments made in the ordinary course of business of expanding the system to provide safe and reliable transmission service").

[100] *See* Exh. No. NPT-200 at 16-17 (Muntz).

[101] *Id.* at 24-25.

In New Hampshire, Northern Pass must obtain siting approval from the New Hampshire Site Evaluation Committee, which is comprised of members of various state agencies (including, among others, the New Hampshire Department of Environmental Services, the New Hampshire Public Utilities Commission, the New Hampshire Department of Resources & Economic Development, the New Hampshire Department of Health & Human Services, New Hampshire Department of Fish & Game, the New Hampshire Department of Cultural Resources, and the New Hampshire Department of Transportation), each of which must review the application to authorize activities that are subject to its jurisdiction and must determine whether or not to approve the application from its own regulatory perspective.[102]

At the federal level, Northern Pass must obtain a Presidential Permit from the U.S. Department of Energy ("DOE"). DOE is responsible for developing an Environmental Impact Statement ("EIS") pursuant to the requirements of the National Environmental Policy Act.[103] Northern Pass may also need to obtain special use permits from the U.S. Forest Service and the U.S. Fish and Wildlife Service. In addition, Northern Pass must obtain permit approvals from the Army Corps of Engineers under the Clean Water Act

[102] *Id.* at 26-27.

[103] *Id.* at 25.

(in consultation with the U.S. Environmental Protection Agency), and approval by the Federal Aviation Administration.[104]

b. Financial Risks and Challenges

In their joint testimony, Messrs. Auseré and Lubbock explain that the NPT Line represents a major transmission investment and is several orders of magnitude larger than a typical new transmission line or upgrade.[105] They also conclude that the seller's risks under the TSA exceed the risks inherent in a typical regulated transmission project in several respects. In recent years, NU has been investing large amounts of capital to upgrade its transmission system. NU will continue to do so in the coming years. For instance, for the period 2001 through 2009, NU spent $2.8 billion in new transmission construction. For the period 2011 through 2015, NU is expected to spend an additional $2.8 billion in new transmission projects, including the NPT Line.

Similarly, NSTAR's $275 million investment in the NPT Line represents a major investment for NSTAR and is part of an ambitious transmission capital investment program through which NSTAR projects to almost double its transmission rate base to approximately $1.6 billion within five years. Within this overall program, there will be internal competition for capital funding.

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[104] *Id.* at 25-26.

[105] *See* Exh. No. NPT-300 at 10-11 (Auseré/Lubbock); *see also* Exh. No. NPT-302 (cost forecast and spending timeline).

Messrs. Auseré and Lubbock discuss the fact that the large capital expenditures required for the NPT Line will result in significant negative cash flows during the construction period. This is due to the fact that the TSA does not provide for inclusion of CWIP in rate base during the construction period, which distinguishes this participant-funded project from most of the other transmission projects that have received incentive rate treatment under Order No. 679.[106]

Messrs. Auseré and Lubbock also explain that with respect to the NPT Line, Northern Pass bears a higher level of financial risk relative to a regulated transmission project developed and built under the ISO-NE regional planning process.[107] For example, the TSA is a "single-payer" contract, which means that the success of the contract depends upon the credit and cooperation of one customer, and that this dependence on one customer is unlike a typical utility transmission project under the New England regional planning process where NU and NSTAR would recover their costs from a large class of customers (i.e., all New England load).[108] In this respect, if HQ Hydro Renewable and its guarantor were to fail financially, Northern Pass would not have a single committed customer for the NPT Line.[109]

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[106] *Id.* at 13-14.

[107] *Id*. at 14-16.

[108] *Id.* at 14-15.

[109] *Id.* at 15.

Further, Messrs. Auseré and Lubbock note that under the TSA, HQ Hydro Renewable has multiple rights to terminate the TSA, including the right to terminate at any time for convenience, and that the risk of customer termination is higher than would exist for a regulated transmission project constructed under the ISO-NE regional transmission plan.[110] They explain that while Northern Pass would be entitled to reimbursement of costs previously incurred upon early termination by HQ Hydro Renewable, HQ Hydro Renewable would not be required to pay the net present value of the equity return Northern Pass would have received during the remaining balance of the term (i.e., lost opportunity costs) unless HQ Hydro Renewable terminates the TSA during the commercial operation phase for convenience.[111] Thus, Northern Pass and its owners bear the risk that they will be able to employ their equity capital in alternative projects that offer a comparable return on investment in a timely manner.

They also explain that if there is a delay caused by Northern Pass in the commercial operation date of the NPT Line, but the Québec Line is ready for start-up and service, Northern Pass will cease to accrue AFUDC and carrying charges.[112] And if the delay continues for another two years, Northern Pass would be required to reimburse HQ

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[110] *Id.* at 18.

[111] *Id.* at 18-19.

[112] *See id.* at 16-17.

Hydro Renewable's affiliate for any resulting amounts the affiliate owes to Hydro-Québec TransÉnergie.[113]

Finally, because HQ Hydro Renewable is a start-up, special purpose entity, Hydro-Québec will provide a parent guaranty with respect to HQ Hydro Renewable's payment obligations under the TSA. Messrs. Auseré and Lubbock explain that this guaranty is subject to a cap, and the cap does not include all potential termination payment obligations.[114] They further explain that the parent guaranty presents other risks that do not exist for typical regulated transmission projects.[115] As a result, Northern Pass is not fully protected against all of its potential losses.[116]

c. Advanced Technology Challenges

The NPT Line also presents risks associated with the use of advanced technologies. As Mr. Muntz explains in his testimony, the implementation of certain new transmission technologies that will be used in the NPT Line requires specialized knowledge, and the planning, engineering, design, operation and maintenance of 300 kV

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[113] *Id*. at 17.

[114] *See id.* at 21.

[115] *Id*.

[116] *Id.* at 18-21.

HVDC bulk transmission lines and substations are quite complex requiring special skill sets.[117] The specifics of advanced technologies are discussed in the Muntz Testimony.

C. The TSA Incentives Are Tailored to the Specific Risks and Challenges of the NPT Line

Under the TSA, Northern Pass and HQ Hydro Renewable have agreed to three incentives that are tailored to offset the specific risks and challenges associated with the NPT Line. Each incentive provision is tailored to address a particular risk or challenge. Taken as a package, these incentives are designed to offset the substantial risks and challenges presented by this particular undertaking in order to ensure the completion of the NPT Line.

a. The ROE Provision

The Commission has explained that the primary purpose of an incentive return on equity is to help attract capital investment to a transmission investment that can offset the risks and challenges faced by a project.[118] In Order No. 679, the Commission explained that an incentive ROE makes a "transmission project more attractive [to investors], and therefore more likely" to be constructed.[119] Further, in several cases, the Commission held that when an applicant has demonstrated that its project is not a routine transmission

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[117] *Id.* at 32-38.

[118] Order No. 679 at PP 24-26, 91.

[119] *Id.* (stating that "the Commission will approve an ROE at the upper end of the zone of reasonableness for new infrastructure investments that meet the requirements of section 219").

investment, that applicant has also demonstrated that the project meets the nexus requirement for an ROE incentive.[120]

As discussed above, the scope, effect, risks and challenges of the NPT Line demonstrate that the NPT Line is a large-scale, non-routine transmission project that carries unique risks. To reflect and compensate for these risks and challenges, the parties to the TSA have agreed to the ROE provision, which is designed to provide returns commensurate with the risks that Northern Pass faces in connection with the project. This ROE provision is particularly appropriate given that the TSA does not provide for the recovery of a return on CWIP during the construction period. For purposes of comparison, in connection with NU and National Grid USA's investments in the New England East-West Solution transmission project, the Commission granted an ROE of 12.89 percent, in addition to 100 percent CWIP and recovery of abandoned plant cost.[121] Similarly, the Middletown-Norwalk project, a joint transmission project by NU and The United Illuminating Company, received an ROE of 12.64 percent from the Commission for most of the project, with an ROE of 13.1 percent for the underground component of that project.[122] More recently, the Commission granted Central Maine Power Company

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[120] *See, e.g.*, *Baltimore Gas and Elec. Co.*, 120 FERC ¶ 61,084 at P 54 ("[W]hen an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive.").

[121] *Ne. Utils. Serv. Co. and Nat'l Grid USA*, 125 FERC ¶ 61,183.

[122] In *Ne. Utils. Serv. Co.*, 124 FERC ¶ 61,044, the Commission granted the Middletown-Norwalk 345 kV transmission project an ROE of 12.64 percent as a transmission project that was

an ROE of 13.14 percent for its large-scale Maine Power Reliability Program Project.[123] The ROE requested is also appropriate in light of the unique risks associated with this particular project. The attached testimony of Messrs. Auseré and Lubbock demonstrates that Northern Pass will take on risks in connection with the NPT Line that do not exist with respect to typical transmission line projects that are included in the ISO-NE Regional System Plan and are subject to regional rate recovery.

b. Termination Rights and Associated Cost Responsibilities under the TSA

Under Article 3 of the TSA, the parties have the right to terminate the TSA under certain circumstances subject to certain cost reimbursement obligations. For instance, HQ Hydro Renewable may terminate the TSA as early as during the development phase for any reason, in which case HQ Hydro Renewable would be responsible for reimbursing Northern Pass for costs and expenses incurred by Northern Pass as set forth in the Letter Agreement (Attachment G to the TSA), subject to an agreed upon cap based on budgets rather than actual costs. Further, HQ Hydro Renewable may terminate the TSA if there is a material cost increase in the construction budget.[124] In that situation, HQ Hydro Renewable would be responsible to pay Northern Pass's costs (including the

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included in the regional transmission plan and completed and in-service by December 31, 2008. NU also demonstrated to the Commission's satisfaction that it met the Order No. 679 incentive requirements.

[123] *Cent. Me. Power Co.*, 125 FERC ¶ 61,079 (2008).

[124] TSA, § 3.3.6.

equity component of the accrued AFUDC). During the construction period, HQ Hydro Renewable may terminate the TSA for convenience, in which case HQ Hydro Renewable would be required to pay Northern Pass's costs (including the debt component of AFUDC) plus an equity component of AFUDC as accrued on Northern Pass's costs plus the greater of (a) 10 percent of the costs incurred by Northern Pass to date that would have been recoverable absent termination of the TSA and (b) $20 million.[125] Other scenarios under which the parties may terminate the TSA include the failure to obtain U.S. regulatory approvals for the NPT Line (§ 3.3.5); failure to obtain the necessary Canadian regulatory approvals for the Québec Line (§ 3.3.4); and a material, uninsured loss occurrence during commercial operations (§ 3.3.9).[126] These termination provisions in the TSA may be characterized as the abandoned plant cost recovery incentive under Order No. 679.

Order No. 679 permits the recovery of 100 percent of prudently incurred costs associated with abandoned transmission projects "if such abandonment is outside the control of management," as such incentive is an "effective means to encourage transmission development by reducing the risk of non-recovery of costs."[127] Moreover,

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[125] *Id.*, § 3.3.8.

[126] In their testimony, Mssrs. Auseré and Lubbock discuss the risks that Northern Pass face with respect to the termination provisions under the TSA. Exh. No. NPT-300 at 15, 18-19.

[127] Order No. 679 at P 163.

the Commission has determined that allowing recovery of abandoned plant costs is appropriate where certain regulatory approvals are outstanding.[128]

Under the TSA, Northern Pass will have the right to recover the costs it has already incurred, including AFUDC, if the NPT Line were to be abandoned under the circumstances set forth in the TSA. Northern Pass will lose the right to recover a return on its anticipated equity investment in the project, a substantial lost opportunity cost that is described in the testimony of Messrs. Auseré and Lubbock. As such, the NPT Line faces numerous uncertainties and the parties have negotiated and agreed to certain termination rights and the parties' cost responsibilities should those termination provisions be exercised. As the Commission has recognized, "the recovery of abandonment costs is an effective means of encouraging transmission development by reducing the risk of non-recovery of costs."[129]

c. Regulatory Asset for Certain Pre-Commercial Operation Costs

Northern Pass is seeking authorization to establish a regulatory asset for certain costs that Northern Pass has incurred and will continue to incur prior to the NPT Line's commercial operation date that do not meet the requirements to be included in CWIP (i.e., those costs not included in FERC Account 107). Under the TSA, the parties have

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[128] *See PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068 at P 47 (2008); *S. Cal. Edison Co.*, 121 FERC ¶ 61,168 at P 72 (2007).

[129] *Pac. Gas & Elec. Co.*, 123 FERC ¶ 61,067 at P 36 (2008) (citing Order No. 679 at P 163).

agreed that Northern Pass's recovery of such costs will be deferred until the project enters commercial operation and then recovered from HQ Hydro Renewable through the formula rate. Such costs exclude TSA negotiation costs but may include costs of AC upgrades billed to Northern Pass prior to the commercial operation date by third parties constructing such upgrades, and routine costs associated with Northern Pass during this period, such as accounting, cash management, and other administrative costs. Northern Pass proposes to amortize this regulatory asset over a three-year period commencing on the commercial operation date of the project.[130] The establishment of this regulatory asset will allow Northern Pass to recover those costs that are incurred prior to the commercial operation date and is consistent with other regulatory assets approved by the Commission in other Order No. 679 proceedings.[131]

D. The Interrelationship Between the Requested Incentives

In Order No. 679-A, the Commission stated that, in determining whether an applicant has met the nexus test, the Commission will examine "the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project."[132] In this case, the incentive rate provisions under the TSA were carefully negotiated and agreed to

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[130] Exh. No. NPT-500 at 12 (Griffin).

[131] *See ITC Great Plains*, 126 FERC ¶ 61,223 at P 74; *Allegheny Energy, Inc.*, 116 FERC ¶ 61,058 at P 99.

[132] Order No. 679-A at P 21.

by Northern Pass and HQ Hydro Renewable. The incentives are appropriate for the large investment being made and the special risks and challenges associated with the NPT Line. Each provision is designed to address a particular risk.

The proposed ROE provision is designed to promote investment in a large, international transmission project that involves a number of risks and challenges that do not exist for a typical regulated transmission project, as described by Messrs. Auseré and Lubbock. Dr. Avera also concludes that the proposed ROE is justified, especially in light of the risks involved in the development, siting and construction of the NPT Line, as well as the unique risks that Northern Pass bears under the TSA relative to a regulated transmission project developed and built under the ISO-NE regional planning process.[133]

The termination provisions under the TSA are targeted at mitigating the risk that the NPT Line may be cancelled for reasons outside of Northern Pass's control. The regulatory asset is designed to allow Northern Pass to recover certain pre-commercial operation costs in these circumstances.

Each of these rate provisions is individually designed to address a different risk, but they all were extensively negotiated and agreed to by the parties as an integrated package of incentives that work together in order to ensure that this important transmission project is completed in a timely manner. The Commission has stated that a

[133] Exh. No. NPT-600 at 81-83, 84-85 (Avera).

package of incentives may be appropriate for large transmission projects, and has authorized similar incentive packages for projects that are comparable to this one.[134] Further, the Commission's acceptance of the termination provisions in the TSA does not warrant a change in the requested ROE awarded to Northern Pass – particularly in view of the fact that the ROE is well below the upper end of the zone of reasonableness and coupled with the fact that the TSA does not provide for inclusion of any CWIP in rate base during the construction period.

E. The Resulting Rates Are Just and Reasonable

An applicant seeking incentives under Order No. 679 must demonstrate that the resulting rates are just and reasonable and not unduly discriminatory or preferential under FPA Section 205. Northern Pass's agreed-to rate provisions under the TSA meet this requirement.

1. ROE

The Commission has recognized that "[t]here is no single, scientifically correct rate of return, but a zone of reasonableness within which the regulator's judgment must be exercised."[135] The courts have likewise held that the Commission has broad discretion

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[134] In Order No. 679 at P 94, the Commission stated that "a large new interstate transmission project that reduces congestion or increases reliability can face substantial risks that the ordinary transmission investment does not."

[135] *Transcon. Gas Pipe Line Corp*., 60 FERC ¶ 61,246 at 61,822 (1992); *see also Tenn. Gas Pipeline Co*., 46 FERC ¶ 61,089 (1989).

to set an ROE within the zone of reasonableness.[136] In Order No. 679 and several Commission orders, the Commission expressed a willingness to grant incentive ROEs at the upper end of the zone of reasonableness in order to encourage utilities to build much needed transmission.[137] The 12.56 percent ROE is well within the range of reasonable returns as determined by Dr. Avera based upon a DCF analysis consistent with the Commission's requirements. Specifically, the proposed 12.56 percent ROE is 386 basis points below the high end of the zone of reasonableness as calculated by Dr. Avera for the national proxy group.

2. Terminations Rights and Associated Cost Responsibility under the TSA

Messrs. Auseré and Lubbock testify about the importance of allowing termination rights in the TSA (similar to abandoned plant incentives approved in Order No. 679 cases).[138] While Northern Pass does not anticipate that the NPT Line will be terminated, there are numerous permitting and siting issues that are out of Northern Pass's control, and the assurance that certain project costs will be recoverable allows Northern Pass to

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[136] *Pub. Serv. Co. of N.M. v. FERC*, 832 F.2d 1201 (10th Cir. 1987); *NEPCO Mun. Rate Comm. v. FERC*, 668 F.2d 1327, 1345 (D.C. Cir. 1981).

[137] *See, e.g.*, *Startrans IO, L.L.C.*, 122 FERC ¶ 61,306 at P 26 (2008) (zone of reasonableness - 7.63 to 13.67 percent, ROE granted: 13.5 percent); *Atl. Path 15, LLC*, 122 FERC ¶ 61,135 at P 20 (2008) (zone of reasonableness – 7.63 to 13.67 percent, ROE granted: 13.5 percent). The Commission has also granted ROEs at the top boundary of the zone. *See, e.g.*, *Ozark Gas Transmission Sys.*, 68 FERC ¶ 61,032 at 61,108 (1994) (granting an "ROE at the top of the zone of reasonableness").

[138] Exh. No. NPT-300 at 23-24 (Auseré/Lubbock).

begin ordering equipment, reserving labor and acquiring rights of way. Moreover, the prospect for primary cost recovery in the event that the TSA is terminated allows Northern Pass to move forward with the development of the NPT Line at this time.[139]

3. Regulatory Asset for Recovery of Certain Pre-Commercial Operation Costs

The TSA provides for Northern Pass to create a regulatory asset to recover certain costs that may be incurred prior to the commercial operation date and which are not included as CWIP.[140] The regulatory asset is reasonable and necessary in order to allow Northern Pass an opportunity to recover all NPT Line expenses, including those incurred prior to the effective date of the formula rate in the TSA.[141]

The Commission has approved similar requests for regulatory assets under Order No. 679. For example, in *Western Grid Development, LLC*, 130 FERC ¶ 61,056 at P 102 (2010), the Commission granted Western Grid's request for authorization to establish a regulatory asset. The Commission noted that granting this incentive would "help compensate [Western Grid] for the risks associated with the long-lead time necessary for constructing the Projects," and that "[g]ranting this incentive encourages development of more transmission infrastructure, thereby fulfilling the goals of FPA section 219."[142]

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[139] *Id.*

[140] TSA, §§ 8.1.2(e)-(f).

[141] Exh. No. NPT-300 at 25-26 (Auseré/Lubbock).

[142] *W. Grid. Dev.* at P 102.

Similarly, in *ITC Great Plains, LLC*, 126 FERC ¶ 61,223 at P 52 (2009), the Commission granted an incentive for pre-commercial costs as regulatory assets to give the utility "more regulatory certainty that it will be able to recover the costs . . . [g]iven the size of the projects and their construction lead time."[143]

VII. PUBLIC POLICY CONSIDERATIONS

As stated earlier in this transmittal letter, the Commission should accept the TSA and the three TSA incentive rate provisions on the basis that these are just and reasonable provisions that facilitate the arrangements freely negotiated by the parties. Thus, the TSA should be summarily approved under the *Mobile*-Sierra doctrine without the need for any further showings and without changes or modifications. Alternatively, Northern Pass requests that if the Commission does not accept the three TSA rate provisions under the *Mobile-Sierra* doctrine, then the Commission should find that these provisions fully meet the Commission's Order No. 679 standards. Very recently, the Commission has articulated another basis upon which it has authority to grant transmission incentives. Thus, to the extent necessary, Northern Pass also requests that the Commission approve these three incentives pursuant to its public policy evaluation under section 205 of the FPA.[144]

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[143] *See also Tallgrass Transmission LLC*, 125 FERC ¶ 61,248 at P 63 (2008).

[144] *See, e.g., S. Cal. Edison Co.*, 133 FERC ¶ 61,107 (2010); *S. Cal. Edison Co.*, 133 FERC ¶ 61,108 (2010).

As discussed above, the NPT Line will provide important public policy benefits in that it will allow the import of 1,200 MW of low carbon, predominantly hydro-electric power that will displace fossil-fired generation and help to reduce greenhouse emissions, which will help New England in meeting environmental requirements under the RGGI. Further, as noted, the NPT Line (i) is a large-scale transmission project that will increase transfer capability between Québec and New England by 1,200 MW; (ii) will reduce transmission congestion between ISO-NE and Québec, expand the supply in the competitive supply market and reduce LMPs in New England, as explained in the CRA Report; (iii) will provide economic benefits in terms of job creation and increasing local tax bases; and (iv) will face significant risks and challenges.

In addition to the public policy benefits of this project and the incentive rate provisions, the other rates, terms and conditions of the TSA are designed to be consistent with Commission policies in many important respects. As explained herein, the rates are cost-based, subject to prudency challenges, and recovered through a formula rate mechanism consistent with the mechanisms accepted and approved for numerous other transmission providers. In accordance with Commission policy, operation of the NPT Line will be turned over to ISO-NE pursuant to the TOA. Other provisions ensure that the Commission's open access policies, such as Order No. 890 roll-over rights to HQ Hydro Renewable, and rights of third parties to use unscheduled capacity are

preserved.[145] Management and administration of capacity releases, pricing, scheduling, reporting and other administrative functions associated with open access operations are structured to comply with Commission requirements and procedures and are to be conducted by one or more independent entities.[146] Thus, the TSA is not in conflict with general Commission policies, and, in fact, furthers such policies in multiple respects.

VIII. ACCOUNTING

Mr. Griffin describes the various accounting-related matters relevant to this filing. He explains that the investors will record contributions made to Northern Pass as investment in subsidiaries on their respective balance sheets, and that Northern Pass will record these receipts as equity and maintain separate capital accounts for each of NU and NSTAR.[147] He also explains that after Northern Pass closes its books each month, the capital accounts of NU Ventures and NSTAR Ventures will be adjusted to reflect the net income or net loss of Northern Pass.[148]

Mr. Griffin also explains that the TSA provides for Northern Pass to recover from HQ Hydro Renewable, over the last five years of the forty-year term, the estimated costs of required decommissioning, net of salvage value, which is subject to true-up after all

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[145] TSA, § 10.1.

[146] *Id.*, § 10.3.

[147] Exh. No. NPT-500 at 6-7 (Griffin).

[148] *Id.* at 9.

decommissioning activities and costs have been expended.[149] He explains that if decommissioning is required, Northern Pass will record an asset retirement obligation ("ARO"), and will record a regulatory asset for the expenses related to the ARO. The regulatory asset will represent the amount that will be recovered during the last five years of the contract.[150] To the extent necessary, Northern Pass requests the Commission's approval for this regulatory asset. The basis for recording the regulatory asset is that the TSA provides for the deferred recovery of required decommissioning costs. In these circumstances, recording a regulatory asset is appropriate under the Commission's accounting rules.[151] Northern Pass is not including the regulatory asset itself in rate base, however.[152]

IX. ADVANCED TECHNOLOGY STATEMENT

Order No. 679 requires applicants for incentive rate treatments to include a technology statement describing the advanced technologies that have been considered

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[149] *Id.* at 16.

[150] *Id.* at 16-17.

[151] *See Pioneer Transmission, LLC,* 130 FERC ¶ 61,044 at P 28 (2010) (noting that a regulatory asset is appropriate for utility costs if it is "probable that such items will be included in a different period(s) [than they would otherwise be expensed] for purposes of developing rates that the utility is authorized to charge for its utility services") (citing 18 C.F.R. Part 101 (USofA), Account 182.3 (2009)).

[152] The ARO asset, the regulatory asset, and the ARO are expected to offset each other, and all of these accounts will be excluded from rate base and accordingly will not earn a return. However, there may be impacts on the calculation of Total Accumulated Deferred Income Taxes in the formula rate due to book-tax timing differences, so the formula rate includes an adjustment to offset such impacts. *See* Exh. No. NPT-500 at 14-15 (Griffin).

and, if not employed, an explanation of the reasons why they were not.[153] As Mr. Muntz testifies, the NPT Line will utilize a number of advanced technologies to enhance the performance of the NPT Line.[154]

X. AFFILIATE TRANSACTIONS

As noted above, Northern Pass currently has no employees; however, it will have access to the utility expertise it needs through service contracts with NUSCO. Mr. Griffin explains the various services that NUSCO will provide to Northern Pass and how those services will be billed.[155] This will allow Northern Pass to take advantage of services provided by its affiliates without any profit being earned by the affiliates in connection with the transactions.

XI. CORRESPONDENCE AND COMMUNICATIONS

Correspondence and service regarding this filing should be sent to the following individuals, who should be placed on the official service list in this proceeding:

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[153] Order No. 679 at P 302.

[154] Exh. No. NPT-200 at 32-38 (Muntz).

[155] Exh. No. NPT-500 at 3-4 (Griffin).

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A hard copy of this filing has been served on the New England state commissions indicated on the attached Service List and HQ Hydro Renewable. Additionally, a link to the filing will be posted on www.transmission-nu.com and www.Northernpass.us.

XII. PROVISIONAL REQUEST FOR WAIVERS

Ms. Taupier's testimony shows the application of the formula rate for the first full calendar year of commercial operation, beginning on January 1, 2016, in lieu of full Statements AA through BM (except Statement BL).[156] Although Northern Pass believes this is an initial rate filing, it provides the information required under both Sections 35.12 and 35.13 of the Commission's regulations that are reasonably applicable to the Commission's review of the TSA. To the extent that this approach may require waivers of Section 35.13 of the regulations, Northern Pass respectfully requests such waivers, including waiver of the full Period I-Period II data requirements, and waiver of the requirements in Section 35.13(a)(2)(iv) to determine if and the extent to which a

[156] Exh. No. NPT-400. Ms. Taupier sponsors Statement BL as Exhibit No. NPT-402.

proposed change constitutes a rate increase based on Period I-Period II rates and billing determinants.[157] Good cause exists for such waiver if the Commission finds that Section 35.13 of the regulations applies. The abbreviated statements and the testimony submitted as attachments to this filing provide ample support for the reasonableness of the proposed formula rate. Detailed statements of Northern Pass's cost of service are not needed where the proposed rates are formulary and will be based on actual costs as reflected in the Northern Pass's audited FERC Form 1 filings. This is particularly true here, in view of the early stage of project development. Further, such waiver would be consistent with Commission precedent for formula rates of this nature.[158]

In addition, although Northern Pass believes that this filing includes sufficient information to meet the Commission's filing requirements, it requests waiver of any applicable regulations to allow the filing to take effect in the manner described. Northern Pass also states that no expenses or costs in connection with this tariff have been alleged

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[157] Since there is no pre-existing rate and Northern Pass has never provided service before, Section 35.13(a)(2)(iv) is inapplicable.

[158] *Ne. Utils. Serv. Co. and Nat'l Grid USA*, 125 FERC ¶ 61,183 (2008), *reh'g pending* (granting waiver of cost-of-service information under sections 35.13(a)(2)(iv); 35.13(d)(1) and (2), 35.13(d)(6), and section 35.13(h)); *Pub. Serv. Elec. and Gas Co.*, 124 FERC ¶ 61,303 at PP 23-24 (granting waiver of Sections 35.13(d)(1)-(2), 35.13(d)(5), and 35.13(h)); *Okla. Gas & Elec. Co.*, 122 FERC ¶ 61,071 at P 41 (2008) (same); *Am. Elec. Power Serv. Corp.*, 120 FERC ¶ 61,205 at P 41 (2007) (granting waiver of Period I and II data); *Commonwealth Edison Co.*, 119 FERC ¶ 61,238 at PP 92-94 (2007) (granting waiver of Period I and II data and cost-of-service statements); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219 at P 57 (2007) (same); *Duquesne Light Co.*, 118 FERC ¶ 61,087 at P 79 (granting waiver of Sections 35.13(d)(1)-(2) and 35.13(h)); *Idaho Power Co.*, 115 FERC ¶ 61,281 at P 20 (2006) (granting waiver of Period II data); *Allegheny Power Sys. Operating Cos.*, 111 FERC ¶ 61,308 at PP 55-56 (2005) (granting waiver of Period I and II data).

or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory practices.

XIII. CONCLUSION

For the reasons set forth above, Northern Pass requests that the Commission accept for filing the TSA, as submitted, without further investigation or suspension.

Respectfully submitted,

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Appendix A

Transmission Service Agreement
Exhibit No. NPT-100

Tariff Submitter: Northern Pass Transmission LLC
FERC Tariff Program Name: FERC FPA Electric Tariff
Tariff Title: FERC Tariffs
Tariff Record Proposed Effective Date: February 14, 2011
Tariff Record Title: Rate Schedule No. 1
Option Code: A

TRANSMISSION SERVICE AGREEMENT

by and between

NORTHERN PASS TRANSMISSION LLC,

as Owner

and

H.Q. HYDRO RENEWABLE ENERGY, INC.,

as Purchaser

Dated: October 4, 2010

EXECUTION COPY

TRANSMISSION SERVICE AGREEMENT

by and between

NORTHERN PASS TRANSMISSION LLC,

as Owner

and

H.Q. HYDRO RENEWABLE ENERGY, INC.,

as Purchaser

Dated: October 4, 2010

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TRANSMISSION SERVICE AGREEMENT

This TRANSMISSION SERVICE AGREEMENT (this "Agreement"), dated as of October 4, 2010 (the "Execution Date"), is made and entered into by and between Northern Pass Transmission LLC, a limited liability company organized and existing under the laws of the State of New Hampshire ("Owner"), and H.Q. Hydro Renewable Energy, Inc., a corporation organized and existing under the laws of the State of Delaware ("Purchaser"). Owner and Purchaser are hereinafter sometimes also referred to individually as a "Party" or collectively as the "Parties."

W I T N E S S E T H:

WHEREAS, Purchaser is an indirect, wholly-owned subsidiary of Hydro-Québec (as defined below);

WHEREAS, Purchaser anticipates that surplus power, which consists predominantly of low-carbon and renewable hydroelectricity, will be available from the Hydro-Québec System (as defined below) for export into the U.S.;

WHEREAS, on May 22, 2009, FERC (as defined below) issued a declaratory order, as thereafter confirmed by FERC on December 29, 2009, approving the structure of a cost-based, participant-funded transmission project to deliver power from the Province of Québec into New England (as defined below), including a long-term bilateral transmission service agreement with a cost-based rate ceiling, subject to FERC approval of such agreement under Section 205 of the Federal Power Act (as defined below);

WHEREAS, in order to permit the delivery of power from the Hydro-Québec System for sale into the U.S., Hydro-Québec TransÉnergie ("TransÉnergie"), a division of Hydro-Québec, intends to develop, construct, own and maintain a 1,200 MW +/-300 kV high-voltage direct current ("HVDC") transmission line from the converter station at the Des Cantons substation in the Province of Québec to the U.S. Border (as defined below) (as further delineated in the diagram in Attachment A, the "Québec Line");

WHEREAS, Hydro-Québec Production ("HQP"), another division of Hydro-Québec, intends to acquire from TransÉnergie firm transmission service over the Québec Line to permit the delivery of at least 1,200 MW of power into the U.S.;

WHEREAS, Purchaser intends to acquire from HQP, or another Affiliate (as defined below) of Purchaser, electrical capacity and the associated electrical energy at the U.S. Border for resale into the U.S.;

WHEREAS, Owner is a single purpose, indirect subsidiary of Northeast Utilities (as defined below) and NSTAR (as defined below), created to develop, construct, own and maintain a 1,200 MW +/-300 kV HVDC transmission line extending from the U.S. Border to a direct current ("DC") to alternating current ("AC") converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire (the transmission line and converter station, as more fully described in Attachment A, the "HVDC Line");

WHEREAS, in order to interconnect the HVDC Line with the bulk power systems in New England, Owner intends to develop, construct, own and maintain a radial 345 kV AC transmission line extending from the southern terminus of the HVDC Line to the Deerfield substation in the State of New Hampshire (together with the Franklin substation at its northern terminus and the associated equipment at its southern terminus, as more fully described in Attachment A, the "AC Line," and together with the HVDC Line, the "Northern Pass Transmission Line");

WHEREAS, ISO-NE (as defined below) may require, and Purchaser may desire, certain AC Upgrades (as defined below) to be developed, constructed, owned and maintained by certain transmission owners other than Owner (which may include Affiliates of Northeast Utilities or NSTAR) within their existing service territories in New England in order to interconnect the Northern Pass Transmission Line with the New England Transmission System (as defined below) in a safe and reliable manner, and Purchaser may desire the construction of certain Additional AC Upgrades (as defined below);

WHEREAS, Owner desires to sell to Purchaser Firm Transmission Service (as defined below) and Additional Transmission Service (as defined below), and Purchaser desires to acquire from Owner Firm Transmission Service and Additional Transmission Service, at the rates and on the terms and conditions hereinafter set forth.

NOW, THEREFORE, in consideration of the foregoing and the respective representations, warranties, covenants, agreements and conditions set forth herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound hereby, the Parties hereby agree as follows:

ARTICLE 1

DEFINITIONS AND RULES OF INTERPRETATION

Section 1.1. Definitions. As used herein, the following terms shall have the following respective meanings:

"AC" has the meaning provided in the recitals to this Agreement.

"AC Line" has the meaning provided in the recitals to this Agreement.

"AC Line Agreement" has the meaning provided in Section 8.6(c).

"AC Line Owner" has the meaning provided in Section 8.6(f).

"AC Upgrade Approvals" means, collectively, any Governmental Approvals or Third Party Consents, in each case, that are required to commence construction of the AC Upgrades.

"AC Upgrade Costs" has the meaning provided in Section 8.5(c).

"AC Upgrade Owners" means, collectively, any Person responsible for constructing one or more AC Upgrades pursuant to a Facilities Agreement.

"AC Upgrades" means, collectively, (a) any additions, upgrades, reinforcements or other modifications to the New England Transmission System that ISO-NE determines pursuant to Section I.3.9 of the ISO-NE Tariff to be required, at a minimum, to interconnect the Northern Pass Transmission Line at the Delivery Point with the New England Transmission System and (b) any such other additions, upgrades, reinforcements or modifications that are (i) identified as part of the transmission project interconnection review by ISO-NE of the Northern Pass Transmission Line in connection with the Section I.3.9 process that Purchaser desires to be constructed and (ii) described in a written notice given by Purchaser to Owner within sixty (60) days after the issuance by ISO-NE of the final Section I.3.9 report. The facilities designated as AC Upgrades may be subject to change in accordance with Section 8.6(g)(iii).

"Additional AC Upgrades" means, collectively, any additions, upgrades, reinforcements or other modifications to the New England Transmission System identified in the Forward Capacity Market qualification process for the sale of 1,200 MW of electrical capacity over the Northern Pass Transmission Line that Purchaser desires to be constructed; provided that Purchaser has notified Owner in writing of such intent within ten (10) Business Days after the date on which a capacity sale for 1,200 MW over the Northern Pass Transmission Line is first cleared in the Forward Capacity Market.

"Additional Financing" means any revolving credit loan or any other financing or indebtedness of any nature for which Owner is liable (other than the Term Financing) (a) that is incurred by Owner to finance or refinance any direct or indirect costs and expenses in connection with the Northern Pass Transmission Line (i) before the Distribution Date (A) under a short-term borrowing arrangement between Owner and one or more of its Affiliates pursuant to the terms of the Northeast Utilities System Money Pool, as filed with FERC, as such terms may be amended from time to time, or (B) at an interest rate not to exceed the lesser of (1) Northeast Utilities' actual cost of borrowing and (2) LIBOR plus two hundred twenty-five (225) basis points, or (ii) after the Commercial Operation Date and (b) the costs for which are recoverable under the Formula Rate in accordance with Article 8. Additional Financing, together with contributions to the equity capital of Owner, shall fund such costs and expenses in a manner consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Additional Lender" means any Person that commits to provide Additional Financing.

"Additional Transmission Service" has the meaning provided in Section 7.1.2.

"Affiliate" means, with respect to a specified Person, any other Person that directly or indirectly Controls, is Controlled by or is under common Control with the specified Person; provided, however, that, with respect to Purchaser, a Person shall not be an "Affiliate" of Purchaser unless such Person is Hydro-Québec (including, for the avoidance of doubt, a division of Hydro-Québec) or Controlled by Hydro-Québec.

"AFUDC" means Owner's allowance for funds used during construction of the Northern Pass Transmission Line, as calculated in accordance with FERC's Uniform System of Accounts.

"Agreement" has the meaning provided in the preamble to this Agreement.

"Alternate Manager" has the meaning provided in Section 13.2(a).

"Ancillary Services" means Ancillary Services, as defined in the ISO-NE Tariff.

"Annual Plan and Operating Budget" means an annual statement that sets forth in reasonable detail the projected Revenue Requirement for the applicable period, including interest expenses, Taxes and all other costs or expenses that are (a) projected to be incurred during the applicable period in connection with the Northern Pass Transmission Line and (b) recoverable under the Formula Rate in accordance with Article 8. Without limiting the generality of the foregoing, the Annual Plan and Operating Budget shall include the Maintenance Plan and the Capital Plan.

"Applicable Law" means any duly promulgated federal, national, state, provincial or local law, regulation, rule, ordinance, code, decree, judgment, directive or judicial or administrative order, permit or other duly authorized and valid action of any Governmental Authority, including any binding interpretation of any of the foregoing by any Governmental Authority, which is applicable to a Person, its property or a transaction.

"Authorized Representatives" has the meaning provided in Section 13.2(a).

"Average Availability" has the meaning provided in Section 16.4(c).

"Base ROE" means the ROE of the New England transmission owners accepted or approved by FERC for Regional Transmission Service, excluding any incentive or other adders approved by FERC.

"Bankruptcy Code" means the United States Bankruptcy Code, 11 U.S.C. § 101 *et seq*.

"Budgeted Amount" has the meaning provided in Section 17.1.1(d)(iii).

"Business Day" means any day except Saturday, Sunday or any other day on which the Federal Reserve member banks are required or authorized to close for business.

"Canadian Approvals" means, collectively, those Governmental Approvals and Third Party Consents, in each case, that are required to commence construction of the Québec Line in a manner consistent with Attachment A, other than the Operational Approvals, all as set forth in Attachment D.

"Canadian Regulatory Event" means a determination by Purchaser, including a reasonable basis for such determination, that (a) one or more Canadian Approvals (i) is reasonably unlikely to be obtained by the Third Anniversary despite the use of commercially

reasonable efforts by Purchaser and its Affiliates or (ii) contains or is reasonably likely to contain modifications or conditions that are reasonably unacceptable to Purchaser or its Affiliates or (b) the continuation by Purchaser or one or more of its Affiliates of the regulatory or other processes required to obtain one or more Canadian Approvals would be reasonably likely to have a material adverse effect on the business, operations or financial condition of Purchaser or one or more of its Affiliates.

"Capital Plan" means an annual plan for the capital expenditures to maintain the Northern Pass Transmission Line in accordance with Good Utility Practice in order to provide Firm Transmission Service, which plan shall include a description of the scope and nature of the Planned CapEx, the planned outages and overhauls of the Northern Pass Transmission Line associated therewith, and a budget itemized on a monthly basis for the same, which budget shall include all Planned CapEx Costs projected to be incurred with respect to the foregoing activities.

"Capital Structure" means the ratio of (a) the total amount of Owner's debt divided by Owner's total capitalization to (b) the total amount of Owner's equity capital divided by Owner's total capitalization, as such amounts are determined from time to time in accordance with FERC's Uniform System of Accounts.

"Capped Guaranteed Obligations" has the meaning provided in Section 17.1.1(a)(i).

"Carrying Charges" has the meaning provided in Section 8.1.2(e)(iii).

"COD Notice" has the meaning provided in Section 4.1(c).

"Commercial Operation" means the availability of the Northern Pass Transmission Line for the provision of Firm Transmission Service in accordance with this Agreement.

"Commercial Operation Date" has the meaning provided in Section 4.1(c).

"Commissioning" means (a) with respect to Northern Pass Transmission Line, the start-up and testing activities required to demonstrate that the Northern Pass Transmission Line is ready for Commercial Operation and (b) with respect to the Québec Line, the start-up and testing activities required to demonstrate that the Québec Line is ready for commercial operation, consistent with Section 4.2(f).

"Confidential Information" means (a) any documents, analyses, compilations, studies, or other materials prepared by or information received from a Party or its representatives that contain or reflect written or oral data or information that is privileged, confidential, or proprietary and that is marked or otherwise clearly identified as "confidential" or "proprietary" or with words of like meaning, or (b) any subsequently prepared documents, analyses, compilations, studies, or other materials or information that are derived from any of the documents, analyses, compilations, studies, or other materials or information described in the foregoing clause (a). Without limiting the generality of the foregoing, all information provided to Purchaser or Owner or their respective Managers under Section 2.3(a)(iii), Section 5.1.2(e)(iii), Section 5.2.1(a), Section 5.2.2(a), Section 5.2.3(a), Section 5.2.4(b), Section 6.3(a), Section 6.3(b)(iv), Section

6.4(a), Section 6.6(a), Section 9.3.2(a), Section 14.2(b), Section 17.1.1(f) and Section 18.1(a) shall be deemed to be Confidential Information, whether or not such information is marked as "confidential" or "proprietary."

"Consent" means, with respect to a Person, any approval, consent, permit, license, decree, certificate or other authorization of or from such Person.

"Construction Authorizations" means, collectively, those Governmental Approvals and Third Party Consents, in each case, that are required to commence construction of the Northern Pass Transmission Line, other than the Operational Approvals.

"Construction Budget and Schedule" has the meaning provided in Section 5.2.2(a).

"Construction Contract" means any contract entered into by Owner that provides for the engineering, procurement or construction of the Northern Pass Transmission Line.

"Construction Costs" means, collectively, all direct and indirect costs that are (a) incurred by Owner in connection with the Northern Pass Transmission Line before the Commercial Operation Date and recorded in FERC Account No. 107 – Construction Work in Progress (including costs incurred before the Effective Date that are included in such account, but excluding costs associated with the drafting and negotiation of this Agreement) and (b) recoverable under the Formula Rate in accordance with Article 8.

"Construction Loan Agreement" means an agreement by and between Owner, as borrower thereunder, and Hydro-Québec Lender, pursuant to which Hydro-Québec Lender shall finance a portion of the Project Costs with loans to Owner on a senior secured basis. Loans under the Construction Loan Agreement, together with contributions to the equity capital of Owner, shall fund all Project Costs in a manner consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Construction Phase" means the period commencing forty-six (46) days after the issuance of the FERC Order and ending on the day immediately preceding the Commercial Operation Date or upon the earlier termination of this Agreement pursuant to its terms (regardless of whether or not any such day is a Business Day).

"Construction Progress Report" has the meaning provided in Section 5.2.4(b).

"Contract Capacity" means (a) 1,200 MW or (b) such lesser amount as may be established by the Commissioning of the Northern Pass Transmission Line, in each case, as measured at the Delivery Point.

"Contract Year" means each calendar year during the Term, except that (a) the first Contract Year shall commence on the Commercial Operation Date and terminate on the following December 31st and (b) the final Contract Year shall terminate at the end of the Term.

"Control" (including its correlative meanings "Controlled by" and "under common Control with") means, with respect to a Person, the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of the specified Person,

whether through ownership of voting securities or partnership or other ownership interests, by contract or Applicable Law or otherwise. Notwithstanding anything herein to the contrary, each of Northeast Utilities and NSTAR shall be deemed to "Control" Owner for purposes of this Agreement.

"Contractor" means Hydro-Québec Contractor or any other Person that agrees to provide engineering, procurement or construction services with respect to the Northern Pass Transmission Line pursuant to a Construction Contract.

"Cost-of-Service Estimate" means a non-binding statement that sets forth in reasonable detail a good faith estimate of the Revenue Requirement for the first full year during the Operation Phase calculated in accordance with the Formula Rate and applicable FERC rules and regulations.

"Critical Energy Infrastructure Information" means any information defined as Critical Energy Infrastructure Information by FERC pursuant to 18 C.F.R. § 388.113, and shall include all Critical Infrastructure Protection (CIP) standards (CIP-002 through CIP-009) established by NERC.

"DC" has the meaning provided in the recitals to this Agreement.

"Decommissioning" means the performance of the work required to (a) retire the Northern Pass Transmission Line and dismantle the materials, equipment and structures comprising the Northern Pass Transmission Line and (b) restore and rehabilitate any land affected by the construction or dismantlement of the Northern Pass Transmission Line, in each case, as required by Applicable Law.

"Decommissioning Costs" means, collectively, any costs and expenses that are incurred by Owner to Decommission the Northern Pass Transmission Line in accordance with this Agreement.

"Decommissioning Estimate" has the meaning provided in Section 9.3.3(c).

"Decommissioning Fund" has the meaning provided in Section 9.3.3(b).

"Decommissioning Liquidated Damages" has the meaning provided in the Purchaser Guaranty.

"Decommissioning Payment Date" has the meaning provided in Section 9.3.3(c).

"Decommissioning Payment Formula " means the following formula:

$$\frac{c}{[(1 + c)^{60} - 1]}$$

Where:

c is the reasonably expected monthly rate of return on amounts deposited into the Decommissioning Fund (expressed as a percentage).

"Decommissioning Payment Period" has the meaning provided in Section 9.3.3(a).

"Decommissioning Plan" has the meaning provided in Section 9.3.2(a).

"Delivery Point" means the southern terminus of the Northern Pass Transmission Line at the Deerfield substation in the State of New Hampshire, as illustrated in Attachment A. This definition may be subject to change in accordance with Section 8.6(g)(i).

"Design Capability" means the maximum amount of electric power that the materials, equipment and structures comprising the HVDC Transmission Project will be designed to transfer bidirectionally in a safe and reliable manner, which amount shall be sufficient to permit the north-to-south delivery of not less than 1,200 MW of electrical energy at the Delivery Point.

"Design Materials" means, collectively, any engineering or technical study, project design, report, analysis, compilation, regulatory filing or other similar data or document prepared by Owner, any Affiliate of Owner or any third-party contractor in connection with the Northern Pass Transmission Line, other than any privileged communications or proprietary intellectual property rights.

"Determined Cap" means the amount determined in accordance with Section 17.1.1 from time to time.

"Development Phase" means the period commencing on January 1, 2009 and ending on the day immediately preceding the commencement of the Construction Phase or upon the earlier termination of this Agreement pursuant to its terms (regardless of whether or not any such day is a Business Day).

"Dispute" means any dispute, controversy or claim of any kind whatsoever arising out of or relating to this Agreement, including the interpretation of the terms hereof or any Applicable Law that affects this Agreement, or the transactions contemplated hereunder, or the breach, termination or validity thereof.

"Dispute Notice" has the meaning provided in Section 18.1(a).

"Distribution Date" means the date on which funds are initially distributed by Hydro-Québec Lender under the Construction Loan Agreement.

"Effective Date" has the meaning provided in Section 3.1.

"EPC Costs" means, collectively, any costs and expenses for which Owner is liable pursuant to any Construction Contract, other than costs and expenses for which Purchaser shall have agreed in writing to reimburse to Owner in the event this Agreement is terminated under Section 3.3.3. For the avoidance of doubt, "EPC Costs" shall include any penalties, damages, fees or other amounts that Owner is required to pay as a result of the termination of any Construction Contract, other than penalties, damages, fees or other amounts for which Purchaser shall have agreed in writing to reimburse to Owner in the event this Agreement is terminated under Section 3.3.3.

"Estimated Wind-Down Costs" means the aggregate amounts described in clause (c) of the definition of "Owner's Costs" that reasonably would be expected to be incurred by Owner upon an early termination of this Agreement, subject to the exclusions to such definition.

"Excluded Claims" means any (a) claims of any Affiliate of Purchaser arising under the TransÉnergie OATT, (b) claims of any Persons residing in, or arising from events in, the Province of Québec (other than claims of any Persons residing in the Province of Québec that arise out of physical injuries suffered in the U.S.) and (c) claims arising out of a contract between Purchaser and any third party.

"Excused Outages" has the meaning provided in Section 7.3(a).

"Execution Date" has the meaning provided in the preamble to this Agreement.

"Existing Guaranty" has the meaning provided in Section 17.1.1(e).

"Expert Arbitration" has the meaning provided in Section 18.3.1(b).

"Expert Arbitrator" means a natural person who (a) is neutral and impartial, (b) has knowledge and expertise in the electric power industry, (c) has not had any commercial relationship with any Party or an Affiliate of a Party (whether as an employee, contractor or otherwise) for at least five (5) years before being appointed an arbitrator hereunder and (d) is fluent in the English language. A natural person shall not qualify as an "Expert Arbitrator" if his or her spouse, children, parents or siblings (x) has a financial interest in the outcome of any Dispute or (y) does not satisfy the criteria described in the foregoing clause (c).

"Expert Arbitrator Candidates" has the meaning provided in Section 18.3.1(a).

"Export Authorizations" means one or more Export Authorizations issued by the U.S. Department of Energy as required for the exportation of electric power into Canada.

"Extended Outage" has the meaning provided in Section 16.4(a).

"Extraordinary CapEx" means, collectively, any capital improvements and projected upgrades, replacements and repairs to the Northern Pass Transmission Line that are (a) required to maintain the Northern Pass Transmission Line in accordance with Good Utility Practice in order to provide Firm Transmission Service and (b) not set forth in the Capital Plan for the applicable period.

"Extraordinary CapEx Costs" means, collectively, all direct and indirect costs and expenses that are (a) incurred by Owner in connection with Extraordinary CapEx and (b) recoverable under the Formula Rate in accordance with Article 8.

"Extraordinary CapEx Plan" has the meaning provided in Section 6.6(a).

"Facilities Agreement" has the meaning provided in Section 8.5(a).

"Federal Power Act" means the United States Federal Power Act of 1935, as amended, 16 U.S.C. § 791a *et seq*.

"FERC" means the Federal Energy Regulatory Commission, or any successor regulatory agency that administers the Federal Power Act.

"FERC Amendment" has the meaning provided in Section 2.2(b)(i).

"FERC Authorization" means, collectively, any FERC order authorizing Owner to provide Firm Transmission Service and Additional Transmission Service, including the FERC Order and any authorization from FERC with respect to the Transmission Operating Agreement, Interconnection Agreements or Facilities Agreements.

"FERC Order" has the meaning provided in Section 2.2(a)(i).

"FERC's Uniform System of Accounts" means 18 C.F.R. Part 101 (2009).

"Financial Transmission Rights" means Financial Transmission Rights, as defined in the ISO-NE Tariff.

"Financing Parties" means, collectively, Hydro-Québec Lender, the Term Loan Lender and any Additional Lender.

"Firm Transmission Service" has the meaning provided in Section 7.1.1.

"Force Majeure" has the meaning provided in Section 16.1(a).

"Formula Rate" means the formula set forth in Attachment B, which formula shall be used to calculate the Transmission Service Payments in accordance with the provisions hereof.

"Good Utility Practice" means those design, construction, operation, maintenance, repair, removal and disposal practices, methods, and acts that are engaged in by a significant portion of the electric transmission industry in the United States during the relevant time period, or any other practices, methods or acts that, in the exercise of reasonable judgment in light of the facts known at the time a decision is made, could have been expected to accomplish a desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be the optimum practice, method, or act to the exclusion of others, but rather to be a spectrum of acceptable practices, methods, or acts generally accepted in such electric transmission industry for the design, construction, operation, maintenance, repair, removal and disposal of electric transmission facilities in the United States. Good Utility Practice shall not be determined after the fact in light of the results achieved by the practices, methods, or acts undertaken but rather shall be determined based upon the consistency of (a) the practices, methods, or acts when undertaken with (b) the standard set forth in the first two (2) sentences of this definition at such time.

"Governmental Approval" means (a) any authorization, consent, approval, license, lease, ruling, permit, tariff, rate, certification, waiver, exemption, filing, variance, claim, order,

judgment, or decree of, by or with, (b) any required notice to, (c) any declaration of or with, or (d) any registration by or with, any Governmental Authority, including any FERC Authorization.

"Governmental Authority" means any government or agency or other political subdivision thereof, including any province, state or municipality, or any other governmental, quasi-governmental, judicial, executive, legislative, administrative, regulatory, public or statutory instrumentality, authority, body, agency, commission, department, board, bureau or entity exercising judicial, executive, legislative, administrative or regulatory functions, any court or arbitrator with authority to bind a party at law, and shall include, to the extent exercising powers delegated by any Governmental Authority acting under Applicable Law, NERC and ISO-NE.

"Hourly Availability" means, with respect to any hour, the availability of the Northern Pass Transmission Line, which shall equal the (a) the Total Transfer Capability for such hour, divided by (b) the Contract Capacity, expressed as a percentage; provided, however, that, for any hour, the availability of the Northern Pass Transmission Line shall not exceed one hundred percent (100%).

"HQP" has the meaning provided in the recitals to this Agreement.

"HVDC" has the meaning provided in the recitals to this Agreement.

"HVDC Line" has the meaning provided in the recitals to this Agreement.

"HVDC Transmission Project" means, collectively, (a) the Québec Line and (b) the Northern Pass Transmission Line.

"Hydro-Québec" means Hydro-Québec, a body politic and corporate, duly incorporated and regulated by the Hydro-Québec Act (R.S.Q., Chapter H-5). As of the Execution Date, Hydro-Québec has four divisions: HQP, TransÉnergie, Hydro-Québec Distribution and Hydro-Québec Équipment.

"Hydro-Québec Contractor" means one or more Affiliates of Purchaser that agree to provide engineering, procurement or construction services with respect to the Northern Pass Transmission Line pursuant to a Construction Contract.

"Hydro-Québec Lender" means Hydro-Québec acting in its capacity as lender under the Construction Loan Agreement.

"Hydro-Québec System" means, collectively, (a) certain generating stations, located in the Province of Québec and owned and operated by Hydro-Québec or its subsidiaries, that produce electric power, which consists predominantly of low-carbon and renewable hydroelectricity, (b) hydroelectric power produced by certain independent power producers, which power Hydro-Québec or its subsidiaries has contractual rights to purchase and resell, and (c) other power purchased by Hydro-Québec or its subsidiaries from third parties for resale.

"ICC" has the meaning provided in Section 18.3.1(c).

"Immunities Act" mean the United States Foreign Sovereign Immunities Act of 1976, 28 U.S.C. § 1602 *et seq*.

"Impasse" has the meaning provided in Section 13.9.

"Income Tax" means any tax imposed on net income by any Governmental Authority.

"Indemnification Notice" has the meaning provided in Section 21.3.

"Indemnified Party" has the meaning provided in Section 21.3.

"Indemnifying Party" has the meaning provided in Section 21.3.

"Initial Allowance" means the amount, expressed in megawatt-hours, equal to (a) the Contract Capacity, multiplied by (b) 720.

"Insolvency Event" means, with respect to a Person, such Person (a) becomes "insolvent," as defined in the Bankruptcy Code, or otherwise becomes bankrupt or insolvent under any Insolvency Laws, (b) has a liquidator, administrator, receiver, custodian, trustee, conservator or similar official appointed with respect to such Person or any material portion of such Person's assets or such Person consents to such appointment, or a foreclosure action is instituted with respect to any material portion of such Person's assets, (c) files a voluntary petition or otherwise authorizes or commences a proceeding or cause of action under the Bankruptcy Code or Insolvency Laws, (d) has an involuntary petition filed against it or acquiesces in the commencement of a proceeding or cause of action as the subject debtor under the Bankruptcy Code or Insolvency Laws, which petition is not dismissed within thirty (30) days after the filing thereof or results in the issuance of an order for relief against such Person, (e) makes or consents to an assignment of its assets in whole or in part, or any general arrangement for the benefit of creditors, or a common law composition of creditors, or (f) generally is unable to pay its debts as they fall due, or admits in writing to such inability.

"Insolvency Laws" means any bankruptcy, insolvency, reorganization or similar laws of the U.S., Canada, or other Governmental Authority, as applicable, other than the Bankruptcy Code.

"Interconnection Agreements" means, collectively, (a) an agreement by and among Owner, TransÉnergie and ISO-NE that sets forth such parties' respective rights and obligations following the interconnection at the U.S. Border of the Northern Pass Transmission Line with the Québec Line and (b) an agreement by and among Owner, PSNH and ISO-NE that sets forth such parties' respective rights and obligations following the interconnection at the Delivery Point of the Northern Pass Transmission Line with certain transmission facilities owned by PSNH. The Interconnection Agreements shall address cost responsibilities and shall include provisions, both technical and otherwise, for safe and reliable interconnected operations of the HVDC Transmission Project following Commercial Operation (including use of the HVDC Transmission Project for the delivery of electric power in emergency circumstances).

"Invoice" means, with respect to a calendar month, an invoice that sets forth the amounts owed to Owner by Purchaser with respect to such month in reasonable detail to evidence the basis for individual billings and charges.

"ISO-NE" means ISO New England Inc., or its successor organization.

"ISO-NE Approval" means approval by ISO-NE to operate the Northern Pass Transmission Line at 1,200 MW.

"ISO-NE Definitions Manual" means the ISO New England Manual for Definitions and Abbreviations, Manual M-35, as in effect from time to time.

"ISO-NE Rules" means the ISO-NE Tariff and all ISO-NE manuals, rules, procedures, agreements or other documents relating to the reliable operation of the electric system in New England and the purchase and sale of electrical energy, electrical capacity and ancillary services, as such govern market participants with respect thereto in the operating jurisdiction of ISO-NE, as in effect from time to time, including the ISO-NE Definitions Manual; provided that such documents are publicly accessible.

"ISO-NE Tariff" means the ISO New England Inc. Transmission, Markets and Services Tariff, FERC Electric Tariff No. 3, as in effect from time to time, on file with FERC, or its successor tariff.

"kV" means kilovolt.

"Letter Agreement" means that certain Letter Agreement for Recovery of Northern Pass Transmission Line Project Development Costs, of even date herewith, a copy of which is attached hereto as Attachment G and made a part hereof.

"Levelized Monthly Decommissioning Payment" has the meaning provided in Section 9.3.1(b).

"LIBOR" means the British Bankers' Association Interest Settlement Rate per annum for deposits in U.S. Dollars (for a term comparable to the interest period selected by Owner in accordance with the Loan Documents for the applicable Additional Financing described in clause (a)(i)(B) of the definition thereof), appearing on the display designated as Page 3750 on the Dow Jones Markets Service (or such other page on that service or such other service designated by the British Bankers' Association for the display of such Association's Interest Settlement Rates for U.S. Dollar deposits) as of 11:00 a.m. (London, England time) or if such Page 3750 is unavailable for any reason, the rate that appears on the Reuters Screen ISDA Page as of such date and such time.

"Loan Agreements" means, collectively, (a) the Construction Loan Agreement, (b) the Term Loan Agreement and (c) the loan and credit agreements entered into by Owner with respect to any Additional Financing.

"Loan Documents" means the Loan Agreements and the other instruments and documents evidencing or securing the obligations of Owner to the Financing Parties under the Loan Agreements.

"Loss Occurrence" means any material loss of, destruction of or damage to, or any condemnation of, the Northern Pass Transmission Line due to an event of Force Majeure.

"Maintenance Plan" means an annual plan for the management, operation and ordinary maintenance of the Northern Pass Transmission Line, which plan shall include a description of the scope and nature of the planned operating and maintenance programs and planned and preventive maintenance procedures for the Northern Pass Transmission Line, the scheduled maintenance and other planned outages of the Northern Pass Transmission Line, and a budget itemized on a monthly basis for the same, which budget shall include all projected O&M Costs projected to be incurred with respect to the foregoing activities.

"Management Committee" has the meaning provided in Section 13.1.

"Manager" has the meaning provided in Section 13.2(a).

"Market Products" means, collectively, all products (however entitled and whether existing now or in the future) that (a) are recognized under ISO-NE Rules, (b) derive from the acquisition of transmission service over the Northern Pass Transmission Line under this Agreement, and (c) can be sold for consideration or otherwise have economic value, including electrical energy, electrical capacity and ancillary services, including reserve products (including spinning and non-spinning reserves).

"Material Adverse Effect" means, with respect to a Party, a material adverse effect on the ability of such Party to perform any of its obligations under this Agreement.

"Membership Pledges" has the meaning provided in Section 17.2.1.

"Minimum Average Availability" means seventy-five percent (75%) of the Contract Capacity.

"Multiyear Outlook" has the meaning provided in Section 6.3(a).

"MW" means megawatt.

"MWh" means megawatt-hour.

"Necessary Administrative Functions" has the meaning provided in Section 10.3(c)(i).

"NEPOOL" means the New England Power Pool and the entities that collectively participate in the New England Power Pool.

"NERC" means the North American Electric Reliability Corporation, or its successor organization.

"Net Decommissioning Costs" means Decommissioning Costs, less any Salvage Proceeds; provided, however, that if the Salvage Proceeds exceed the Decommissioning Costs, then the Net Decommissioning Costs shall equal Zero Dollars ($0).

"Net Present Value of Owner's Equity Return" means the amount obtained by discounting the ROE portion of all remaining Transmission Service Payments that would have been recoverable under this Agreement absent the termination thereof using the ROE (as established pursuant to Section 8.4(b)) in effect as of the applicable termination date, which amount shall be calculated in accordance with customary financial practice and at a discount factor equal to the Base ROE in effect as of the applicable termination date.

"New England" means, collectively, the State of Maine, State of New Hampshire, State of Vermont, Commonwealth of Massachusetts, State of Rhode Island and State of Connecticut.

"New England Transmission System" means New England Transmission System, as defined in the ISO-NE Tariff.

"Non-Excused Outage" has the meaning provided in Section 7.4.1.

"Northeast Utilities" means Northeast Utilities, a public utility holding company organized and existing as a voluntary trust under the laws of the Commonwealth of Massachusetts.

"Northern Pass Transmission Line" has the meaning provided in the recitals to this Agreement. This definition may be subject to change in accordance with Section 8.6(g)(ii).

"NPCC" means the Northeast Power Coordinating Council, Inc., or its successor organization.

"NPCC Approval" means approval by NPCC to operate the Northern Pass Transmission Line at 1,200 MW.

"NSTAR" means NSTAR, a public utility holding company organized and existing as a voluntary association under the laws of the Commonwealth of Massachusetts.

"O&M Costs" means, collectively, all direct and indirect costs and expenses that are (a) incurred by Owner during the Operation Phase in connection with the operation and maintenance of the Northern Pass Transmission Line (excluding Decommissioning Costs) and (b) recoverable under the Formula Rate in accordance with Article 8.

"OASIS Administrator" has the meaning provided in Section 10.3(c).

"OASIS Provider" has the meaning provided in Section 10.3(a).

"OATT Payments" has the meaning provided in Section 4.3.1(b)(i).

"Operation Phase" means the period commencing on the Commercial Operation Date and ending upon the expiration of the Term or earlier termination of this Agreement pursuant to its terms (regardless of whether or not any such day is a Business Day).

"Operational Approvals" means, collectively, (a) the ISO-NE Approval and (b) the NPCC Approval.

"Other Regulatory Event" means a determination by Purchaser, including a reasonable basis for such determination, that one or more Operational Approvals (a) is reasonably unlikely to be obtained by the Third Anniversary or (b) contains or is reasonably likely to contain modifications or conditions that are reasonably unacceptable to Purchaser or its Affiliates.

"Other Transmission Rights" means collectively, any Financial Transmission Rights (or any similar concept), auction revenue rights or other financial or physical transmission rights, in each case, whether existing now or in the future, associated with the Northern Pass Transmission Line or AC Upgrades.

"Outstanding Claim" has the meaning provided in Section 17.1.1(e).

"Owner" has the meaning provided in the preamble to this Agreement.

"Owner Approvals" means, collectively, (a) the Construction Authorizations and (b) those other Governmental Approvals and Third Party Consents, in each case, that are required to develop, construct, own and operate the Northern Pass Transmission Line, other than the Operational Approvals, all as set forth in Attachment C.

"Owner Default" has the meaning provided in Section 15.2.

"Owner Delay" has the meaning provided in Section 4.3.1(a).

"Owner Guaranty" has the meaning provided in Section 17.1.2(a), as in effect from time to time.

"Owner Indemnified Party" has the meaning provided in Section 21.1.

"Owner Retained Property" means, collectively, (a) all fee simple and other interests in real property (including rights-of-way, other easements and leasehold interests in real property), (b) proprietary intellectual property and (c) other intangible property (including development rights), in each case, associated with the Northern Pass Transmission Line.

"Owner's Costs" means an amount equal to the sum of the following, without duplication, (a) all costs and expenses incurred by Owner before the applicable termination date (whether payable before, on or after such date) that would have been recoverable under this Agreement (including under Section 8.1.4, without altering the otherwise applicable burden of proof set forth in Section 8.1.4(b) for prudency challenges) absent the termination thereof, other than Decommissioning Costs and costs and expenses incurred with respect to any Owner Retained Property, plus (b) the debt component of AFUDC, as accrued on the applicable portion

of the costs described in the foregoing clause (a) in accordance with Section 8.1.2 and included in the calculation of Rate Base, plus (c) all wind-down costs, penalties, damages, fees and other amounts that Owner is required to pay to third parties as a result of the termination of this Agreement, any Facilities Agreement or any other contract or lease (excluding contracts or leases with respect to Owner Retained Property) entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, including, for the avoidance of doubt, any penalties, damages, fees or other amounts for which Owner is liable under the Loan Agreements as a result of the prepayment of the loans made to Owner thereunder, but excluding any Decommissioning Costs. In no event shall any penalties, damages, fees or other amounts that Owner is required to pay to its Affiliates qualify as "Owner's Costs" unless Owner is liable for such penalties, damages, fees or amounts pursuant to a transaction or other arrangement that is on terms and conditions at least as favorable to Owner, when taken as a whole, as would have been obtained (at the time entered into) in a comparable arm's-length transaction or arrangement with a Person other than an Affiliate of Owner; provided, however, that, if such transaction or arrangement has been accepted or approved by FERC or any other Governmental Authority that specifically reviews the Affiliate relationship in such transaction or arrangement, then such transaction or arrangement shall be deemed to be a comparable arm's-length transaction or arrangement. For the avoidance of doubt, the amounts described in the foregoing two (2) sentences shall not include any amounts previously charged to Purchaser and recovered by Owner under the Formula Rate.

"Owner's Costs Plus EAFUDC" means an amount equal to the sum of the following, without duplication, (a) Owner's Costs, plus (b) the equity component of AFUDC, as accrued on the applicable portion of Owner's Costs in accordance with Section 8.1.2 and included in the calculation of Rate Base. For the avoidance of doubt, the amounts described in the foregoing sentence shall not include any amounts previously charged to Purchaser and recovered by Owner under the Formula Rate.

"Owner's Initial Deadline" has the meaning provided in Section 4.3.1(a).

"Owner's Final Deadline" has the meaning provided in Section 4.3.1(b).

"Panel" has the meaning provided in Section 18.3.1(a).

"Parties" and "Party" have the meanings provided in the preamble to this Agreement.

"Person" means any legal person, including any natural person, domestic or foreign corporation, limited liability company, general or limited partnership, joint venture, association, joint stock company, business trust, estate, trust, enterprise, unincorporated organization, any Governmental Authority, or any other legal or commercial entity.

"Planned CapEx" means, collectively, the planned capital improvements and projected upgrades, replacements and repairs to the Northern Pass Transmission Line.

"Planned CapEx Costs" means, collectively, all direct and indirect costs and expenses that are (a) incurred by Owner in connection with Planned CapEx and (b) recoverable under the Formula Rate in accordance with Article 8.

"Position Statement" means a statement of a Party's position on a particular matter or issue and a summary of facts and arguments supporting that position.

"Pre-COD Expenses" mean all costs and expenses that are (a) incurred by Owner in connection with the Northern Pass Transmission Line and the AC Upgrades before the Commercial Operation Date and not included in FERC Account No. 107 – Construction Work in Progress (including the AC Upgrade Costs associated with AC Upgrades that are placed-in-service before the Commercial Operation Date and are included in the regulatory asset described in Section 8.1.2(e), but excluding costs and expenses associated with the drafting and negotiation of this Agreement) and (b) recoverable under the Formula Rate in accordance with Article 8.

"Preliminary Monthly Decommissioning Payment" has the meaning provided in Section 9.3.3(a)(i).

"Preliminary Budget and Schedule" has the meaning provided in Section 5.2.1(a).

"Prior Claims" has the meaning provided in Section 17.1.1(e).

"Project Assets" means, collectively, all materials, equipment and structures owned by Owner, excluding the Owner Retained Property.

"Project Budget" means, collectively, (a) a budget consisting of line item estimates of all Project Costs, including reasonable contingency amounts applied to individual line item estimates or to the Project Costs as a whole, and (b) a budget of estimated AC Upgrade Costs projected to be incurred before the Commercial Operation Date in such detail as can reasonably be obtained by Owner from the AC Upgrade Owners, recognizing that one or more Project Budgets will be completed and delivered before the date on which the AC Upgrades are formally identified under this Agreement.

"Project Costs" means, collectively, (a) the Construction Costs, and (b) the Pre-COD Expenses.

"Project Debt" means Owner's debt to finance the costs and expenses incurred by Owner in connection with the Northern Pass Transmission Line under (a) the Construction Loan Agreement, (b) the Term Loan Agreement and (c) the loan and credit agreements entered into by Owner with respect to any Additional Financing, the aggregate amount of which debt shall be consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Project Debt Obligations" means all obligations of every nature of Owner from time to time owed to any Financing Party under the Loan Documents, whether for principal, interest or payments for early termination of interest rate hedging agreements, fees, expenses, indemnification or otherwise and all guarantees of any of the foregoing. Notwithstanding the foregoing, unless otherwise agreed in writing by Purchaser, if the outstanding principal amount of the Project Debt Obligations (together with the face amount of letters of credit and the amount of unfunded commitments under the Loan Documents) is in excess of the principal amount of Project Debt that Owner is permitted to incur consistent with its obligations under Section 5.6 and Section 8.3(a), then Project Debt Obligations shall include only (a) that portion of the principal amount of Project Debt that Owner is so permitted to incur consistent with its

obligations under Section 5.6 and Section 8.3(a), plus (b) interest, fees and reimbursement obligations in respect of such portion of such principal amount, plus (c) any other principal consisting of capitalization or funding of such interest, fees or reimbursement obligations.

"Project Schedule" means a schedule setting forth the proposed engineering, procurement, construction and testing milestone schedule for (a) the Northern Pass Transmission Line based upon the Construction Contracts and (b) the AC Upgrades based upon such information as can reasonably be obtained by Owner from the AC Upgrade Owners, recognizing that one or more Project Schedules will be completed and delivered before the date on which the AC Upgrades are formally identified under this Agreement.

"PSNH" means Public Service Company of New Hampshire, a corporation organized and existing under the laws of the State of New Hampshire.

"PTF" has the meaning provided in Section 8.6(b).

"Purchaser" has the meaning provided in the preamble to this Agreement.

"Purchaser Default" has the meaning provided in Section 15.1.

"Purchaser Guaranty" has the meaning provided in Section 17.1.1(a), and includes any Purchaser Guaranty reissued in accordance with Section 17.1.1(g) or Section 17.1.1(i).

"Purchaser Indemnified Party" has the meaning provided in Section 21.2.

"Purchaser Mortgage" has the meaning provided in Section 17.2.1.

"Purchaser's Deadline" has the meaning provided in Section 4.3.2(b).

"Purchaser's Decommissioning Balance" has the meaning provided in Section 9.3.4.

"Purchaser's Lien" has the meaning provided in Section 17.2.1.

"Purchaser's Security Documents" has the meaning provided in Section 17.2.1.

"Québec Damages" has the meaning provided in Section 7.4.2.

"Québec Line" has the meaning provided in the recitals to this Agreement.

"Rate Base" has the meaning provided in Section III.A. of Attachment B.

"Rate Base Calculation" has the meaning provided in Section 16.3(c)(i).

"Real Power Losses" means energy consumed by the electrical impedance characteristics of the Northern Pass Transmission Line.

"Reconstruction Costs" means, with respect to a Loss Occurrence, collectively, all costs and expenses that are (a) incurred by Owner to reconstruct or otherwise repair the Northern

Pass Transmission Line following such Loss Occurrence, net of insurance proceeds and other amounts received by Owner in connection therewith (excluding any proceeds of any liability insurance policy or any insurance proceeds or other amounts payable to any Financing Party, unless such amounts payable are permitted under the applicable Loan Documents to be applied to such Loss Occurrence), and (b) recoverable under the Formula Rate in accordance with Article 8.

"Reconstruction Plan" has the meaning provided in Section 16.3(c)(i).

"Recovery" has the meaning provided in Section 21.6.

"Redetermination Certificate" has the meaning provided in Section 17.1.1(f).

"Redetermination Date" means (a) during the Construction Phase, (i) the first day of the first calendar month following the delivery of the first Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2, and (ii) each anniversary of such date thereafter until the date immediately preceding the Commercial Operation Date, and (b) during the Operation Phase, (i) the Commercial Operation Date, (ii) the first day of the third Contract Year after the Commercial Operation Date, and (iii) the first day of each third Contract Year thereafter.

"Regional Rates" means the rates for Regional Transmission Service.

"Regional Transmission Service" means Regional Transmission Service, as defined in and provided under the ISO-NE Tariff.

"Replacement Transmission Cost" means, with respect to each hour of a period of time during a Non-Excused Outage, the amount equal to (a)(i) the positive difference, if any, between (A) the price per MWh that Purchaser paid for replacement transmission service acquired by Purchaser during such hour to New England from the international border between the Province of Québec and the United States and (B) the price per MWh that Purchaser would have paid under this Agreement based upon the full Transmission Service Payment due for such period, multiplied by (ii) the amount of transmission capacity (expressed in MW) that Purchaser acquired for such hour (capped at the amount of unavailable transmission capacity during such hour resulting from a Non-Excused Outage), plus (b) any reasonable transaction costs incurred by Purchaser in connection with the foregoing purchase.

"Revenue Requirement" means the annual transmission revenue requirement of Owner, as determined in accordance with the Formula Rate.

"ROE" has the meaning provided in Section 8.4(a).

"Rules" has the meaning provided in Section 18.3.2(a).

"Salvage Proceeds" has the meaning provided in Section 9.3.5(b)(ii).

"Satisfying Amount" has the meaning provided in Section 17.1.1(e).

"Scheduling Rules" has the meaning provided in Section 7.1.4.

"Security Agreement" has the meaning provided in Section 17.2.1.

"Settlement Amount" means an amount equal to the sum of the following, (a) Owner's Costs Plus EAFUDC, plus (b) an amount equal to the greater of (i)(A) the sum of all Project Costs incurred before the applicable termination date (whether payable before or after such termination date) that would have been recoverable under this Agreement absent the termination thereof, multiplied by (B) one-tenth (0.10) and (ii) Twenty Million Dollars ($20,000,000).

"Stated Cap" means the amount set forth in Section 1(a)(i) of the Purchaser Guaranty, as in effect from time to time.

"Subordination Agreement" has the meaning provided in Section 17.2.2.

"Subsequent Use" has the meaning provided in Section 9.2.

"Target Date" means the date that coincides with the guaranteed substantial completion date as established under the principal Construction Contract, which date is preliminarily expected to be in 2015.

"Taxes" means, collectively, all categories of taxes identified as recoverable under the Formula Rate.

"Technical Dispute" has the meaning provided in Section 18.3.1(b).

"Technical Dispute Notice" has the meaning provided in Section 18.3.1(b).

"Term" has the meaning provided in Section 3.2.

"Term Financing" means a financing evidenced by a Term Loan Agreement.

"Term Financing Parameters" means parameters established by the Management Committee for the terms and conditions of a Term Financing in accordance with Section 5.1.2(e).

"Term Financing Procedures" has the meaning provided in Section 5.1.2(e)(i).

"Term Loan Agreement" means the loan and credit agreements entered into by Owner with respect to any refinancing of the Construction Loan Agreement or any subsequent refinancing of the loans made under such loan and credit agreements. Loans under the Term Loan Agreement shall fund such refinancing in a manner consistent with Owner's obligations under Section 5.6 and Section 8.3(a).

"Term Loan Lender" means, collectively, any Person that commits to provide loans to Owner under the Term Loan Agreement.

"Termination Payment" means an amount equal to the sum of the following, without duplication, (a) Owner's Costs Plus EAFUDC, plus (b) the Net Present Value of Owner's

Equity Return as of the applicable termination date. For the avoidance of doubt, the amounts described in the foregoing sentence shall not include any amounts previously charged to Purchaser and recovered by Owner under the Formula Rate.

"Third Anniversary" means the third (3rd) anniversary of the Effective Date.

"Third Party Claim" has the meaning provided in Section 21.3.

"Third Party Consent" means any Consent of a Person other than a Governmental Authority.

"Third Party Rehearing Request" means any request by a third party for rehearing of the FERC Order.

"Total Transfer Capability" means the Total Transfer Capability of the Northern Pass Transmission Line, as defined in, and established in accordance with, the ISO-NE Tariff and determined by ISO-NE for each hour.

"TransÉnergie" has the meaning provided in the recitals to this Agreement.

"TransÉnergie OATT" means the Hydro-Québec Open Access Transmission Tariff, as amended or accepted by the Régie de l'énergie from time to time.

"Transfer" has the meaning provided in Section 23.1(a).

"Transmission Operating Agreement" means an agreement entered into by and between Owner and ISO-NE for transmission operating services over the Northern Pass Transmission Line under which operating control (as defined in such agreement) of the Northern Pass Transmission Line is transferred from Owner to ISO-NE.

"Transmission Operator" means ISO-NE acting in its capacity pursuant to the Transmission Operating Agreement.

"Transmission Service Payment" has the meaning provided in Section 8.1.2(b).

"Unfavorable FERC Decision" has the meaning provided in Section 2.2(a)(ii).

"United States" or "U.S." means the United States of America.

"U.S. Border" means the location on or near the international border between the State of New Hampshire and the Province of Québec where the HVDC Line and the Québec Line interconnect.

"U.S. Regulatory Event" means a determination by Owner, including a reasonable basis for such determination, that (a) one or more Construction Authorizations (i) is reasonably unlikely to be obtained by the Third Anniversary despite the use of commercially reasonable efforts by Owner and its Affiliates or (ii) contains or is reasonably likely to contain modifications or conditions that are reasonably unacceptable to Owner or one or more of its Affiliates or (b) the

continuation by Owner or one or more of its Affiliates of the regulatory or other processes required to obtain one or more Construction Authorizations would be reasonably likely to have a material adverse effect on the business, operations or financial condition of Owner or one or more of its Affiliates.

Section 1.2. Interpretation. In this Agreement, unless the context otherwise requires, the following rules shall apply to the usage of terms:

Section 1.2.1. Singular; Plural; Gender; Corollary Meaning. The singular shall include the plural and vice versa, and any pronoun shall include the corresponding masculine, feminine and neuter forms. If a term is defined as one part of speech (such as a noun), then it shall have a corresponding meaning when used as another part of speech (such as a verb).

Section 1.2.2. Coordinating Conjunctions. The word "or" shall have the inclusive meaning represented by the phrase "and/or."

Section 1.2.3. Self Reference. The words "hereof," "herein," "hereto" and "hereunder" and words of similar import when used in this Agreement shall, unless otherwise expressly specified, refer to this Agreement as a whole and not to any particular provision of this Agreement.

Section 1.2.4. Inclusive References. The words "include," "includes" and "including" when used in this Agreement shall be deemed to be followed by "without limitation" or "but not limited to," whether or not they are in fact followed by such words or words of like import.

Section 1.2.5. Incorporation by Reference. Any reference in this Agreement to an "Article," "Section" or other subdivision or to an "Attachment" or other schedule or attachment shall be references to an article, section or other subdivision of, or to a schedule or attachment to, this Agreement, unless otherwise stated, and all such Articles, Sections, and Attachments are incorporated into this Agreement by reference (all of which comprise part of one and the same agreement with equal force and effect). In the event of any conflict or other inconsistency between the main body of this Agreement and any attachment or schedule to this Agreement, the provisions of the main body of this Agreement shall prevail.

Section 1.2.6. Subsequent Acts. Any references in this Agreement to any statute shall be deemed to refer to such statute, as amended or replaced from time to time, including by succession of comparable successor statute, and all rules and regulations promulgated thereunder. In the event any index or publication referenced in this Agreement ceases to be published or a concept defined by reference to any such index or publication ceases to exist, each such reference shall be deemed to be a reference to a successor or alternate index, publication or concept reasonably agreed to by the Parties. Unless specified otherwise, a reference to a given agreement or instrument, and all schedules and attachments thereto, shall be a reference to that agreement or instrument as modified, amended, supplemented and restated, and as in effect from time to time.

Section 1.2.7. Inclusive of Permitted Successors. Unless otherwise expressly stated, references to any Person also include its permitted successors and assigns.

Section 1.2.8. Time Computation. In this Agreement, in the computation of periods of time from a specified date to a later specified date, the word "from" means "from and including" and the words "to" and "until" each means "to but excluding."

Section 1.2.9. Business Days. Whenever this Agreement refers to a number of days, such number shall refer to calendar days unless Business Days are specified. Whenever any action must be taken under this Agreement on or by a day that is not a Business Day, such action may be validly taken on or by the next day that is a Business Day, and in the case of payments (including refunds of payments), no interest shall accrue on the amount due; provided that such payment is made in full on the next day that is a Business Day.

Section 1.2.10.Regulatory Approvals. Any Governmental Approval shall be deemed to be received upon issuance, even if such Governmental Approval is subject to appeal or rehearing.

Section 1.2.11.Currency. All references to prices, values or monetary amounts referred to in this Agreement shall be paid in United States currency, unless expressly provided otherwise.

ARTICLE 2

REGULATORY FILINGS AND REQUIRED APPROVALS

Section 2.1. FERC Filing.

(a) As soon as practicable after the Execution Date, but in no event later than sixty (60) days thereafter, Owner shall file this Agreement with FERC pursuant to Section 205 of the Federal Power Act and 18 C.F.R. Part 35. Such filing shall include waiver requests for the Effective Date to occur sixty-one (61) days after the date of such filing, which Effective Date may be more than one hundred twenty (120) days before the Commercial Operation Date.

(b) Owner shall consult with Purchaser as to the appropriate time of such filing. The Parties shall respond promptly to any requests for additional information made by FERC in connection with such filing.

(c) Upon the filing of this Agreement pursuant to Section 2.1(a), Purchaser shall support the approval or acceptance of this Agreement by FERC without modification or condition.

Section 2.2. Modifications to FERC Order.

(a) In the event (i) FERC issues an order accepting or approving this Agreement for filing (the "FERC Order") and (ii) the FERC Order contains modifications or conditions that are unacceptable to a Party, in its sole discretion (an "Unfavorable FERC Decision"), such Party shall deliver a written notice to the other Party

specifying the unacceptable modifications or conditions, which notice shall be delivered within five (5) Business Days following the issuance of the Unfavorable FERC Decision.

(b) In the event of an Unfavorable FERC Decision, the following provisions shall apply:

(i) The Parties may agree upon amendments to this Agreement (the "FERC Amendment") that achieve, as nearly as practicable, the commercial intent of this Agreement as of the Execution Date in a manner consistent with the Unfavorable FERC Decision. The execution and delivery by the Parties of a FERC Amendment shall be without prejudice to either Party's rights under Section 3.3.2.

(ii) Each Party shall retain the right to request a rehearing of the FERC Order regardless of any negotiations that have occurred or are occurring pursuant to clause (b)(i) above; provided, however, that, in the event the Parties execute a FERC Amendment after one or both of the Parties has filed for rehearing, any such rehearing request shall be withdrawn no later than five (5) Business Days after FERC issues an order accepting or approving the FERC Amendment for filing, if such rehearing request is inconsistent with the terms and conditions of this Agreement, as amended. Unless otherwise agreed in writing by the Parties, a filing by either Party of a request for rehearing of the FERC Order shall not toll or otherwise modify any date or time period set forth in this Agreement, including, for the avoidance of doubt, the date upon which the Construction Phase shall commence or the period within which a Party may terminate this Agreement under Section 3.3.2.

Section 2.3. Cooperation.

(a) In addition to their obligations under Section 2.1, Owner and Purchaser shall, and each Party shall use commercially reasonable efforts to cause its Affiliates to, (i) cooperate with each other to prepare, file and effect any applications, notices, petitions, reports or other filings or documentation required under Applicable Law or otherwise necessary, proper or advisable to consummate the transactions contemplated by this Agreement, (ii) provide updates to the other Party on material developments in connection with any such filings or documentation, (iii) provide any non-privileged information reasonably requested by the other Party in connection with any such filings or documentation, (iv) cooperate with each other to use commercially reasonable efforts to obtain all Governmental Approvals and Third Party Consents that are necessary, proper or advisable to consummate the transactions contemplated by this Agreement, including the FERC Order (without modifications or conditions) and the other Owner Approvals, and (v) provide any support reasonably necessary and requested by the AC Upgrade Owners to obtain the AC Upgrade Approvals.

(b) Each Party shall consult with the Management Committee with respect to all characterizations of information relating to the other Party, its Affiliates or the transactions contemplated by this Agreement that are proposed to appear in any filings or documentation contemplated by Section 2.1 or Section 2.3(a). The Management Committee shall promptly provide comments, if any, to the applicable Party on any such characterizations of information. Each Party shall make a good faith effort to take into account any comments made by the Management Committee.

Section 2.4. No Inconsistent Action. Except as provided in Section 18.2 and Article 20, from and after the Execution Date, the Parties shall not undertake, and shall use commercially reasonable efforts to cause their Affiliates not to undertake, any action before FERC, ISO-NE or any other Governmental Authority that is inconsistent with the terms and conditions of this Agreement, including, for the avoidance of doubt, Section 2.1(c) and Section 7.1.5.

ARTICLE 3

EFFECTIVE DATE; TERM

Section 3.1. Effective Date. This Agreement shall become effective and enforceable to the extent permitted by Applicable Law as of the Execution Date. Notwithstanding the foregoing sentence, this Agreement will become effective as a FERC rate schedule upon the effective date set forth in the FERC Order (the "Effective Date").

Section 3.2. Term. The term of this Agreement shall commence on the Execution Date and shall expire on the fortieth (40th) anniversary of the Commercial Operation Date, unless earlier terminated or extended in accordance with the terms hereof (the "Term").

Section 3.3. Termination Rights. This Agreement may be terminated in accordance with the ensuing provisions in this Article 3, subject to any required regulatory review, approvals or acceptances, as applicable. Neither Party shall oppose any termination of this Agreement made in accordance with this Article 3 before FERC or any other Governmental Authority; provided, however, that the foregoing shall not prohibit either Party from challenging or otherwise Disputing whether or not any termination of this Agreement is permitted by this Agreement.

Section 3.3.1. Mutual Agreement. This Agreement may be terminated at any time upon written agreement of the Parties.

Section 3.3.2. For Convenience During the Development Phase.

(a) Prior to the commencement of the Construction Phase, either Party shall have the right to terminate this Agreement by written notice to the other Party. This right may be exercised by either Party for any reason, including, for the avoidance of doubt, an Unfavorable FERC Decision, Third Party Rehearing Request, Impasse or other Dispute with respect to the Preliminary Budget and Schedule (or any part thereof) or failure by Owner and Affiliates of Purchaser to execute term sheets for a Construction Contract or the Construction Loan Agreement.

(b) Except as otherwise provided in Section 3.6, upon termination of this Agreement pursuant to clause (a) above, neither Party shall have any liability to the other Party under this Agreement; provided, however, that, subject to FERC approval, Purchaser shall reimburse Owner for costs and expenses incurred by Owner to the extent provided in, and in accordance with, the Letter Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.2, with

respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.3. U.S. Regulatory Event.

(a) During the Construction Phase, at any time prior to the fifteenth (15th) day after the receipt by Owner or its Affiliates of all Construction Authorizations, Owner shall have the right to terminate this Agreement upon not less than five (5) days' prior written notice to Purchaser in the event of a U.S. Regulatory Event.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs, less EPC Costs (if any); provided, however, that, if (i) this Agreement has been terminated pursuant to clause (a) above and (ii) Owner has failed to comply with the provisions of Section 5.1.2(a)(ii)(A), then, except as otherwise provided in Section 3.6, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.3, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.4. Canadian Regulatory Event or Other Regulatory Event.

(a) During the Construction Phase, at any time prior to the fifteenth (15th) day after the earlier to occur of (i) the receipt by Purchaser or its Affiliates of all Canadian Approvals and the receipt by Owner or an Affiliate of Purchaser of all Operational Approvals and (ii) the Third Anniversary, Purchaser shall have the right to terminate this Agreement upon not less than five (5) days' prior written notice to Owner in the event of a Canadian Regulatory Event or Other Regulatory Event; provided that (A) Purchaser and any of its Affiliates that are responsible for obtaining any Canadian Approval or jointly obtaining the NPCC Approval shall have used commercially reasonable efforts to obtain all of the Canadian Approvals and to jointly obtain the NPCC Approval, in each case, by the Third Anniversary and (B) Purchaser and its Affiliates shall have cooperated with Owner in a manner consistent with Section 2.3 to obtain the ISO-NE Approval by the Third Anniversary.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.4, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.5. Failure to Obtain Certain Approvals.

(a) Unless otherwise agreed in writing by the Parties, this Agreement shall terminate immediately without further action of the Parties in the event any of

the Construction Authorizations, AC Upgrade Approvals or Operational Approvals has not been obtained by the Third Anniversary.

(b) From and after the Third Anniversary, at any time prior to the receipt by Purchaser or its Affiliates of all Canadian Approvals, Owner shall have the right to terminate this Agreement upon not less than five (5) days' prior written notice to Purchaser.

(c) Upon termination of this Agreement pursuant to clause (a) or (b) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC; provided, however, that, if (i) this Agreement has been terminated pursuant to clause (a) above and (ii) Owner has failed to comply with the provisions of Section 5.1.2(a)(ii), then, except as otherwise provided in Section 3.6, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.5, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.6. Material Cost Escalation.

(a) In the event the aggregate amount budgeted for Project Costs, as set forth in a proposed Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i), exceeds, by more than fifteen percent (15%), the aggregate amount budgeted for Project Costs in the most recently approved Construction Budget and Schedule, or, for the initial Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2, the aggregate amount budgeted for Project Costs in the Preliminary Budget and Schedule, Purchaser shall have the right to terminate this Agreement by written notice to Owner delivered no later than sixty (60) days after the receipt by Purchaser's Manager of such proposed Construction Budget and Schedule.

(b) In the event the aggregate amount budgeted for Project Costs, as set forth in a proposed Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i), exceeds, by more than thirty percent (30%), the aggregate amount budgeted for Project Costs in the Preliminary Budget and Schedule, Purchaser shall have the right to terminate this Agreement by written notice to Owner delivered no later than sixty (60) days after the receipt by Purchaser's Manager of such proposed Construction Budget and Schedule.

(c) Purchaser's failure to exercise either of its termination rights pursuant to this Section 3.3.6, (or Purchaser's failure to exercise either of such rights in a timely manner) shall be without prejudice to Purchaser's right to terminate this Agreement (i) pursuant to clause (a) above in the event any proposed Construction Budget and Schedule subsequently delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i) exceeds the most recently approved Construction Budget and Schedule by more than fifteen percent (15%) or (ii) pursuant to clause (b) above in the event any proposed Construction Budget and Schedule subsequently delivered to the Management Committee under Section

5.2.2 or Section 16.3(b)(i) exceeds both (A) the Preliminary Budget and Schedule by more than thirty percent (30%) and (B) the most recently approved Construction Budget and Schedule by any amount.

(d) Upon termination of this Agreement pursuant to this Section 3.3.6, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.6, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.7. Termination of Agreements with Purchaser's Affiliates.

(a) In the event (i) any Construction Contract with Hydro-Québec Contractor is terminated as a result of any default by Owner of its obligations thereunder (provided that such default was not due to a breach by Hydro-Québec Lender of its funding obligation under the Construction Loan Agreement) or (ii) the Construction Loan Agreement is terminated as a result of any default by Owner of its obligations thereunder (provided that such default was not due to a breach by Hydro-Québec Contractor of any of its obligations under a Construction Contract), Purchaser shall have the right to terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice.

(b) Except as otherwise provided in Section 3.6, upon termination of this Agreement pursuant to clause (a) above, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.7, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.8. For Convenience During Construction Phase.

(a) In addition to the termination rights set forth in Section 3.3.4 and Section 3.3.6, during the Construction Phase, Purchaser shall have the right to terminate this Agreement for any other reason by not less than five (5) days' prior written notice to Owner.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, the Settlement Amount; provided, however, that if (x) this Agreement has been terminated pursuant to clause (a) above following an Impasse or other Dispute with respect to the most recent Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2 or Section 16.3(b)(i) as of the date of termination and (y) the line item estimates or contingency amounts set forth in such Construction Budget and Schedule are lower than the cost estimates provided by the applicable Contractor, then Purchaser shall have the right to Dispute such item estimates or contingency amounts pursuant to the

arbitration provisions set forth in Section 18.3. If Purchaser Disputes any such estimate or contingency amount, as described above, then the following provisions shall apply:

(i) In the event any such Dispute is resolved in favor of Purchaser, and the aggregate amount budgeted for Project Costs in the Construction Budget and Schedule determined pursuant to the arbitration provisions set forth in Section 18.3 exceeds, by more than fifteen percent (15%), the aggregate amount budgeted for Project Costs in the most recently approved Construction Budget and Schedule, or, for the initial Construction Budget and Schedule delivered to the Management Committee under Section 5.2.2, the aggregate amount budgeted for Project Costs in the Preliminary Budget and Schedule, then, in lieu of the Settlement Amount, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC.

(ii) In the event any such Dispute is resolved in favor of Purchaser, and the Construction Budget and Schedule determined pursuant to the arbitration provisions set forth in Section 18.3 exceeds both (A) the Preliminary Budget and Schedule by more than thirty percent (30%) and (B) the most recently approved Construction Budget and Schedule by any amount, then, in lieu of the Settlement Amount, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC.

(iii) In the event neither clause (b)(i) nor clause (b)(ii) above applies following resolution of any such Dispute, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, the Settlement Amount.

The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.8, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(a) and Section 9.3.

Section 3.3.9. Loss Occurrence Following Commercial Operation.

(a) In the event (i) a Loss Occurrence during the Operation Phase renders the Northern Pass Transmission Line entirely out-of-service and (ii) the projected Reconstruction Costs, as set forth in the proposed Reconstruction Plan delivered to the Management Committee under Section 16.3(c)(i), exceed, in the aggregate, the amount equal to (A) the unamortized rate base, as set forth in the Rate Base Calculation delivered to the Management Committee under Section 16.3(c)(i), multiplied by (B) fifteen one-hundredths (0.15), Purchaser shall have the right to terminate this Agreement by written notice to Owner delivered no later than sixty (60) days after the receipt by Purchaser's Manager of such Reconstruction Plan and Rate Base Calculation.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC. The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.9, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the

Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(b) and Section 9.3.

Section 3.3.10.For Convenience Following Commercial Operation.

(a) In addition to the termination rights set forth in Section 3.3.9 and Section 3.3.12, from and after the Commercial Operation Date, Purchaser shall have the right to terminate this Agreement for any other reason by not less than thirty (30) days' prior written notice to Owner.

(b) Upon termination of this Agreement pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, the Termination Payment; provided, however, that if this Agreement has been terminated pursuant to clause (a) above within sixty (60) days after the receipt by Purchaser's Manager of a proposed Reconstruction Plan and Rate Base Calculation, then Purchaser shall have the right to Dispute such Reconstruction Plan or Rate Base Calculation pursuant to the arbitration provisions set forth in Section 18.3. If Purchaser Disputes such Reconstruction Plan or Rate Base Calculation, as described above, then the following provisions shall apply:

(i) In the event any such Dispute is resolved in favor of Purchaser, and the projected Reconstruction Costs, as set forth in the Reconstruction Plan delivered to the Management Committee under Section 16.3(c)(i) (or determined pursuant to the arbitration provisions set forth in Section 18.3 in the event of an Impasse with respect thereto), exceed, in the aggregate, the amount equal to (A) the unamortized rate base, as set forth in the Rate Base Calculation delivered to the Management Committee under Section 16.3(c)(i) (or determined pursuant to the arbitration provisions set forth in Section 18.3 in the event of an Impasse with respect thereto), multiplied by (B) fifteen one-hundredths (0.15), then, in lieu of the Termination Payment, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, Owner's Costs Plus EAFUDC.

(ii) In the event clause (b)(i) above does not apply following resolution of any such Dispute, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, the Termination Payment.

The Parties' rights and obligations, following termination of this Agreement pursuant to this Section 3.3.10, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(b) and Section 9.3.

Section 3.3.11.Purchaser Default.

(a) Owner shall have the right to terminate this Agreement in accordance with Section 15.3(a).

(b) Upon the exercise by Owner of its termination rights pursuant to clause (a) above, Owner shall have the right to recover from Purchaser, and

Purchaser shall pay or reimburse to Owner, the Termination Payment. The Parties' rights and obligations, following termination of this Agreement pursuant to clause (a) above, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(b) and Section 9.3.

(c) The exercise by Owner of its termination rights pursuant to clause (a) above shall constitute a waiver by Owner of all other remedies or damages that may be available at law or in equity; provided, however, that Owner shall not waive its right to, and Purchaser shall remain liable for, the Termination Payment, any amounts owed to Owner by Purchaser under Section 3.4, Section 9.3.3(c), Section 9.3.4 or Section 9.3.5(d) and any indemnification obligations of Purchaser to Owner under this Agreement, together with any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Owner to recover the Termination Payment or such indemnified or other amounts.

Section 3.3.12. Owner Default.

(a) Purchaser shall have the right to terminate this Agreement in accordance with Section 15.4(a), Section 15.4(c) or Section 15.4(d).

(b) Except as otherwise provided in Section 3.6, upon the exercise by Purchaser of its termination rights pursuant to clause (a) above, neither Party shall have any liability to the other Party under this Agreement. The Parties' rights and obligations, following termination of this Agreement pursuant to clause (a) above, with respect to the property rights and interests associated with the Northern Pass Transmission Line and the Decommissioning of the Northern Pass Transmission Line are respectively set forth in Section 3.5(c) and Section 9.3.

(c) The exercise by Purchaser of its termination rights pursuant to clause (a) above shall constitute a waiver by Purchaser of all other remedies or damages that may be available at law or in equity; provided, however, that Purchaser shall not waive its right to, and Owner shall remain liable for, any express remedy or measure of damages that are owing to Purchaser or any express modification of Purchaser's payment obligations that have accrued under this Agreement before or as of such termination, any amounts owed to Purchaser by Owner under Section 9.2, Section 9.3.3(d) or Section 9.3.4, any fees and expenses reasonably incurred by Purchaser in enforcing Owner's participation obligation pursuant to Section 18.3.5 and any indemnification obligations of Owner to Purchaser under this Agreement, together with any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover such damages or such indemnified or other amounts owed to Purchaser by Owner.

Section 3.4. Termination Payments.

(a) Within sixty (60) days following the termination of this Agreement pursuant to Section 3.3, Owner shall deliver to Purchaser a preliminary invoice that sets forth Owner's good faith estimate of the amounts owed to Owner by Purchaser under Section 3.3, as such amounts may be adjusted pursuant to clause (c) below. Purchaser shall pay

the amounts set forth in such preliminary invoice within thirty (30) days following its receipt of such preliminary invoice but otherwise in a manner consistent with Section 14.1.

(b) Promptly after the actual amounts owed to Owner by Purchaser under Section 3.3 are known to Owner, but no later than thirty (30) days following the end of the work associated with the Decommissioning of the Northern Pass Transmission Line, Owner shall deliver to Purchaser a final invoice reconciling the estimated amounts owed to Owner by Purchaser under Section 3.3 and paid by Purchaser with the actual amounts owed to Owner by Purchaser under Section 3.3. If and to the extent the total amount paid by Purchaser for the estimated amounts owed to Owner by Purchaser under Section 3.3 is greater than the actual amounts owed to Owner by Purchaser under Section 3.3, then, concurrently with the delivery of such final invoice, Owner shall refund to Purchaser the excess amounts collected, together with interest thereon calculated pursuant to Section 14.5(a), in a single lump sum and in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. If and to the extent the total amount paid by Purchaser for the estimated amounts owed to Owner by Purchaser under Section 3.3 is less than the actual amounts owed to Owner by Purchaser under Section 3.3, then Purchaser shall pay a surcharge to Owner in the amount of such deficiency, together with interest thereon calculated pursuant to Section 14.5(b), in a single lump sum due thirty (30) days following the receipt by Purchaser of such final invoice but otherwise in a manner consistent with Section 14.1. Either Party may deduct and setoff payment of such refund or surcharge, as applicable, against any accrued but unpaid payment obligation of the other Party to such Party hereunder.

(c) Any payments by or on account of any obligation of Purchaser pursuant to Section 3.3 or Section 9.3 shall be made in such amounts as may be necessary for all such payments, after any reduction or withholding for or on account of any present or future taxes, levies, imposts, duties, fees, deductions, withholdings, assessments or other charges imposed, levied, or assessed by or on behalf of any Governmental Authority, and after payment by Owner of any Income Taxes with respect to such amounts (taking into account any reduction in tax or other tax benefits resulting from, or attributable to, any amounts deducted or withheld by Purchaser pursuant to this clause (c)), to yield an aggregate amount that shall not be less than the amounts that Owner was entitled to recover pursuant to Section 3.3 or Section 9.3. If any taxes, levies, imposts, duties, fees, deductions, withholdings, assessments or other charges are required by Applicable Law to be deducted or withheld by Purchaser from any amounts owed to Owner by Purchaser under Section 3.3 or Section 9.3, then (i) Purchaser shall make such deductions or withholdings, and (ii) Purchaser shall timely pay the full amount deducted or withheld to the relevant Governmental Authority in accordance with Applicable Law. Notwithstanding anything herein to the contrary, the computation of the adjustments required pursuant to this clause (c) shall be made without duplication of any Federal Income Taxes, State Income Taxes or any other Taxes included in the definition of Owner's Costs or Decommissioning Costs, as applicable. The reconciliation process provided in clause (b) above shall apply *mutatis mutandis* to the actual adjustments required pursuant to this clause (c).

(d) The Parties acknowledge and agree that the payment of amounts by Purchaser to Owner pursuant to Section 3.3, Section 3.4 or Section 9.3 is an

appropriate remedy and that any such payment does not constitute a forfeiture or penalty of any kind. The Parties further acknowledge and agree that the damages for the termination of this Agreement are difficult or impossible to determine and that the damages calculated under Section 3.3, Section 3.4 or Section 9.3 constitute a reasonable approximation of the harm or loss to Owner as a result thereof.

Section 3.5. Allocation of Property Rights and Interests Following Termination.

(a) The following provisions shall apply upon the termination of this Agreement pursuant to Section 3.3.2, Section 3.3.3, Section 3.3.4, Section 3.3.5, Section 3.3.6, Section 3.3.7 or Section 3.3.8:

(i) Owner shall have the right to retain or dispose of the Owner Retained Property.

(ii) Subject to the receipt by Owner of all amounts owed to it by Purchaser under this Agreement or the Letter Agreement, as applicable, Owner shall promptly deliver to Purchaser a copy of the Design Materials. For a period of three (3) years following the termination of this Agreement, Purchaser shall not use, or permit a third party to use, the Design Materials to develop, with any Person other than Owner or its Affiliates, an HVDC transmission line from the Province of Québec directly into or through the State of New Hampshire, without the prior written consent of Owner.

(iii) Subject to the receipt by Owner of all amounts owed to it by Purchaser under this Agreement or the Letter Agreement, as applicable, Purchaser shall have the option (exercisable by written notice to Owner) to acquire from Owner, without additional cost to Purchaser or compensation to Owner, the Project Assets. In the event Purchaser fails to exercise such option within thirty (30) days after the termination of this Agreement, Owner shall salvage all Project Assets not acquired by Purchaser pursuant to this clause (a)(iii) in accordance with Section 9.3.5(b).

(b) The following provisions shall apply upon the termination of this Agreement pursuant to Section 3.3.9, Section 3.3.10 or Section 15.3(a):

(i) Owner shall have the right to (A) subject to the rights (if any) of any Financing Party under any of the Loan Agreements, retain or dispose of the rights and interests associated with the Northern Pass Transmission Line, including, for the avoidance of doubt, the Owner Retained Property and (B) determine if and when to Decommission the Northern Pass Transmission Line; provided that the Decommissioning, when it occurs, is undertaken in accordance with Section 9.3.

(ii) Purchaser shall have no right to acquire or use any property rights and interests associated with the Northern Pass Transmission Line, except as may be provided in the Purchaser's Security Documents for any accrued but unpaid payment obligation of Owner to Purchaser hereunder.

(c) The following provisions shall apply upon the termination of this Agreement pursuant to Section 15.4(a), Section 15.4(c) or Section 15.4(d):

(i) Subject to the rights (if any) of any Financing Party under any of the Loan Agreements and the rights of Purchaser under the Purchaser's Security Documents or against Purchaser's Lien, Owner shall retain the rights and interests associated with the Northern Pass Transmission Line, including, for the avoidance of doubt, the Owner Retained Property.

(ii) Purchaser's rights with respect to the property rights and interests associated with the Northern Pass Transmission Line shall be governed by the Purchaser's Security Documents.

Section 3.6. Effect of Termination. Except as provided in Section 24.12 for the survival of provisions, upon expiration or other termination of this Agreement pursuant to its terms, each of the Parties shall be released from all of its obligations under this Agreement, other than any accrued but unpaid payment obligation. Notwithstanding the foregoing sentence, upon such expiration or termination of this Agreement, either Party shall have the right to recover any costs or expenses (including reasonable attorneys' fees) reasonably incurred by such Party to recover any amounts owed to such Party by the other Party hereunder or to secure the release of any security or performance assurance provided by or on behalf of such Party after the later to occur of the end of the Term or the date on which any accrued but unpaid payment obligation of such Party to the other Party hereunder shall have been fully, finally and indefeasibly satisfied.

ARTICLE 4

COMMERCIAL OPERATION

Section 4.1. Commercial Operation Date.

(a) Owner shall provide a written non-binding notice to Purchaser no later than sixty (60) days before the date Owner reasonably expects the Commercial Operation Date to occur.

(b) At the reasonable request of Owner made in writing, Purchaser shall, and shall use commercially reasonable efforts to cause its Affiliates to, cooperate with Owner, TransÉnergie and ISO-NE to support the Commissioning of the HVDC Transmission Project.

(c) As soon as practicable after Owner is of the opinion that the conditions to Commercial Operation, as set forth in Section 4.2, have been satisfied, or such conditions have been waived in writing by the Parties (except in the case of Section 4.2(b), Section 4.2(f), Section 4.2(g) and Section 4.2(h), which conditions may be waived in writing by Purchaser, in its sole discretion), Owner shall deliver a written notice to Purchaser specifying the date upon which Commercial Operation shall commence (the "COD Notice"), which commencement date shall occur no earlier than ten (10) Business Days after the receipt by Purchaser of the COD Notice or on such other date as agreed upon by the Parties in writing (such date, the "Commercial Operation Date").

(d) Within five (5) Business Days after the receipt by Purchaser of the COD Notice, Purchaser shall deliver a certificate to Owner either (i) confirming that the conditions set forth in Section 4.2 have been satisfied or duly waived and that Commercial Operation may commence on the Commercial Operation Date or (ii) objecting with reasonable detail to the COD Notice. Purchaser's failure to respond in writing to a COD Notice within such five (5)-Business Day period shall be deemed to be a confirmation that the conditions set forth in Section 4.2 have been satisfied or duly waived. Any Dispute over whether or not the conditions set forth in Section 4.2 have been satisfied or duly waived shall be resolved in accordance with Article 18. Regardless of the resolution of such Dispute, but subject to the limitations provided in Section 4.3.1(a), for purposes of cost recovery under Section 8.1.2, Owner shall have the right to continue to accrue AFUDC on the Construction Costs and Carrying Charges on the Pre-COD Expenses for the period of time pending resolution of such Dispute and until the Commercial Operation Date. Such Construction Costs and Pre-COD Expenses shall include costs and expenses that are (A) incurred by Owner before the Commercial Operation Date to maintain the Northern Pass Transmission Line in good operating condition pending resolution of such Dispute and (B) recoverable under the Formula Rate in accordance with Article 8.

Section 4.2. Conditions Precedent to Commercial Operation. The items set forth in clauses (a) through (h) below shall be conditions precedent to the Commercial Operation of the Northern Pass Transmission Line:

(a) Completion of the Commissioning of the HVDC Transmission Project by Owner (in coordination with ISO-NE) and TransÉnergie;

(b) The Northern Pass Transmission Line has been constructed in accordance with, and is capable of operating at, the Design Capability;

(c) Completion of the AC Upgrades;

(d) The Interconnection Agreements shall be in full force and effect;

(e) The Transmission Operating Agreement shall be in full force and effect and ISO-NE shall have informed Owner that ISO-NE (i) is prepared to assume operational control over the Northern Pass Transmission Line, as defined in, and in accordance with, the Transmission Operating Agreement and (ii) will assume such operational control as of the Commercial Operation Date;

(f) The Québec Line has been constructed in accordance with, and is capable of operating at, the Design Capability;

(g) Receipt by Purchaser of copies of certificates evidencing all outstanding insurance required or otherwise obtained under Section 5.3(a); and

(h) Receipt by Purchaser of an opinion of legal counsel, reasonably satisfactory to Purchaser, that all Governmental Approvals and Third Party Consents required to own and operate the Northern Pass Transmission Line have been obtained.

Section 4.3. Delay in Commercial Operation.

Section 4.3.1. Owner Delay.

(a) If, as a result of an Owner Default, any conditions set forth in Section 4.2 shall not have been satisfied or duly waived within one hundred eighty (180) days following the later to occur of (i) the Target Date and (ii) the date upon which TransÉnergie has certified to Owner in good faith that the Québec Line is ready for Commissioning (such delay, an "Owner Delay," and such one hundred eightieth (180th) day, "Owner's Initial Deadline"), then, for purposes of cost recovery under Section 8.1.2, AFUDC shall not be accrued on the Construction Costs and Carrying Charges shall not be accrued on the Pre-COD Expenses, in each case, from and after Owner's Initial Deadline.

(b) If an Owner Delay continues beyond the second (2nd) anniversary of Owner's Initial Deadline ("Owner's Final Deadline"), then the following provisions shall also apply:

(i) Purchaser shall have the right to recover from Owner, and Owner shall pay or reimburse to Purchaser, for each month (or part thereof) following Owner's Final Deadline during which the Owner Delay is continuing, an amount equal to all penalties, damages, fees or other charges in respect of the Québec Line that are owed and paid by HQP to TransÉnergie, if any, under the TransÉnergie OATT with respect to such month (or part thereof); provided, however, that Owner's maximum liability to Purchaser under this clause (b)(i) shall not exceed, in the aggregate, an amount equivalent to the sum of the transmission service payments in respect of the Québec Line that would have been owed by HQP to TransÉnergie under the TransÉnergie OATT (the "OATT Payments") (exclusive of any penalties, damages, fees or other charges) if the Québec Line was operating at its full expected capacity following its commercial operation for the period commencing on Owner's Final Deadline and ending six (6) months thereafter or upon the earlier termination of this Agreement pursuant to its terms. Any such penalties, damages, fees or other charges, when taken as a whole, shall not exceed the amounts that would have been owed by a Person other than an Affiliate of TransÉnergie in a comparable arm's-length transaction or arrangement under the TransÉnergie OATT. Purchaser shall use commercially reasonable efforts to cause HQP to mitigate the amount of any such penalties, damages, fees or other charges. At Owner's reasonable request, Purchaser shall make available to Owner any information reasonably necessary to support the amounts owed to Purchaser by Owner pursuant to this clause (b)(i).

(ii) The Parties acknowledge and agree that the cessation of the accrual of AFUDC on Construction Costs and Carrying Charges on Pre-COD Expenses, in each case, pursuant to clause (a) above and the payment of amounts by Owner to Purchaser under clause (b)(i) above are an appropriate remedy and that any such modification or payment does not constitute a forfeiture or penalty of any kind. The Parties further acknowledge and agree that the damages for an Owner Delay are difficult or impossible to determine and that the damages calculated hereunder constitute a reasonable approximation of the harm or loss to Purchaser as a result thereof.

(iii) Subject to the discharge by Owner of its obligations under Section 5.7(a), the rights provided in Section 3.3.12 and this Section 4.3.1 shall collectively be the sole and exclusive remedy of Purchaser with respect to an Owner Delay. The foregoing sentence shall not be construed in any way to limit (A) Purchaser's right to recover any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover any amounts owed to Purchaser by Owner under this Agreement, (B) Purchaser's rights and remedies under the Purchaser's Security Documents or Owner Guaranty or against Purchaser's Lien or any other financial assurances held by Purchaser or (C) Purchaser's right to recover payment of any indemnification obligations of Owner to Purchaser pursuant to Section 21.2.

Section 4.3.2. Other Delays. If, for any reason other than an Owner Default, any conditions set forth in Section 4.2 shall not have been satisfied or duly waived by the date upon which Owner has certified to Purchaser in good faith that the Northern Pass Transmission Line is ready for Commissioning, then the following provisions shall apply:

(a) For purposes of cost recovery under Section 8.1.2, AFUDC shall continue to be accrued on the Construction Costs and Carrying Charges shall continue to be accrued on the Pre-COD Expenses, as provided in Section 8.1.2(e)(ii) and Section 8.1.2(e)(iii), in each case, during the period of delay during which any conditions set forth in Section 4.2 have yet to be satisfied or duly waived.

(b) If such delay continues beyond the second (2nd) anniversary of the later to occur of (i) the Target Date and (ii) the date upon which Owner has certified to Purchaser in good faith that the Northern Pass Transmission Line is ready for Commissioning (such second (2nd) anniversary date, "Purchaser's Deadline"), then the Commercial Operation Date shall be deemed to have occurred, and the Operation Phase shall be deemed to have commenced, on Purchaser's Deadline for all purposes under this Agreement (provided this Agreement has not been terminated), and Purchaser shall commence payments of the Transmission Service Payments in accordance with Article 14 as if the Northern Pass Transmission Line had achieved Commercial Operation.

(c) For the avoidance of doubt, during such period of delay at any time before Purchaser's Deadline, Purchaser shall continue to have the right to terminate this Agreement under Section 3.3.8, and, from and after Purchaser's Deadline, Purchaser shall have the right to terminate this Agreement under Section 3.3.10.

ARTICLE 5

GENERAL RIGHTS AND RESPONSIBILITIES OF THE PARTIES

Section 5.1. Responsibilities of the Parties.

Section 5.1.1. Development Phase. The Parties acknowledge and agree that Owner, either directly or through its Affiliates, has commenced the development of the technical design and scope of the Northern Pass Transmission Line consistent with the scope of activities defined in, and the monthly reports and budgets provided under, the Letter Agreement.

Section 5.1.2. Construction Phase.

(a) During the Construction Phase, Owner shall (i) exercise Good Utility Practice to complete, or cause the completion of, all tasks required to construct the Northern Pass Transmission Line and achieve Commercial Operation by the Target Date, in each case, in accordance with the Design Capability and in a manner consistent with Attachment A, (ii) use commercially reasonable efforts (A) to obtain all of the Construction Authorizations by the Third Anniversary, (B) to obtain, jointly with TransÉnergie, the NPCC Approval by the Third Anniversary, (C) to obtain, in consultation with Purchaser or Purchaser's Affiliates, the ISO-NE Approval by the Third Anniversary and (D) to cause Owner's Affiliates that are AC Upgrade Owners to obtain any AC Upgrade Approvals for which such Affiliates are responsible by the Third Anniversary, and (iii) use commercially reasonable efforts to obtain all Owner Approvals (other than the Construction Authorizations) by the Target Date. Provided that Owner has complied with its obligations under Section 2.1, Section 2.3, Section 5.1.2(a)(ii) and Section 5.1.2(a)(iii), Owner shall not be in breach of, or be liable to Purchaser under, this Agreement, and no Owner Default shall occur, as a consequence of Owner's failure to obtain an Owner Approval or an Operational Approval or any AC Upgrade Owner's failure to obtain an AC Upgrade Approval.

(b) The Parties intend that Owner and Hydro-Québec Contractor will use commercially reasonable efforts to enter into, within a commercially reasonable timeframe, a Construction Contract on terms and conditions that are customary for the engineering, procurement and construction of projects of a similar nature to the Northern Pass Transmission Line, but also giving due consideration to the particular context and structure of the transactions contemplated hereby and thereby. The Parties also intend that Owner and Hydro-Québec Lender will use commercially reasonable efforts to enter into, within a commercially reasonable timeframe, the Construction Loan Agreement on terms and conditions that are customary for fully secured project financings of a similar nature to the Northern Pass Transmission Line, but also giving due consideration to the particular context and structure of the transactions contemplated hereby and thereby.

(c) At Purchaser's reasonable request made in writing, Owner shall, and shall use commercially reasonable efforts to cause its Affiliates to, support and cooperate with Purchaser in order to enable Purchaser to enter into one or more facilities agreements to pay for the costs to design, license, construct and operate the Additional AC Upgrades.

(d) Owner shall cooperate with Purchaser and its Affiliates as reasonably necessary for Purchaser or its Affiliates to obtain the Export Authorizations related to the Northern Pass Transmission Line.

(e) The following provisions shall apply with respect to a Term Financing:

(i) No later than three hundred sixty-five (365) days before the Target Date, or such other date as the Management Committee may approve, the Management Committee shall establish a timetable, procedures (the "Term Financing Procedures") and Term Financing Parameters for a Term Financing to refinance the Construction Loan Agreement. No later than three hundred sixty-five (365) days before the maturity date of any Term Financing, the Management Committee shall establish a timetable, Term Financing Procedures and Term Financing Parameters for the refinancing of such Term Financing.

(ii) The Term Financing Parameters shall include a requirement that the Term Financing be on terms and conditions that are customary for fully secured project financings of a similar nature to the Northern Pass Transmission Line, but in no event shall the Term Financing Procedures include any obligation for any Affiliate of Owner to provide a guaranty, capital funds commitment or similar support agreement. The Term Financing Procedures shall require Owner to seek a minimum number of competitive bids (which may be in the form of proposals or commitment letters as specified in the Term Financing Procedures) from potential lenders and shall permit Purchaser or one or more of its Affiliates to submit a competitive bid for the Term Financing. In recognition that the costs of the Term Financing are recoverable under the Formula Rate in accordance with Article 8, the Term Financing Procedures shall also require that Owner negotiate the pricing terms of all or a minimum number of competitive bids for the Term Financing (including interest, fees, amortization and tenor) in good faith as though Owner were bearing such costs itself. Subject to the immediately ensuing sentence, Owner shall comply in all material respects with the timetable, Term Financing Procedures and Term Financing Parameters for the initial Term Financing or any subsequent Term Financing. If, as a result of market conditions, Owner is reasonably unable to comply with such timetable, Term Financing Procedures or Term Financing Parameters, Owner shall consult with the Management Committee, and the Management Committee shall appropriately revise the timetable, Term Financing Procedures or Term Financing Parameters, as applicable, consistent with such market conditions.

(iii) Purchaser shall have the right to review the Term Loan Agreement prior to its execution and effectiveness to confirm that the terms and conditions thereof are not in conflict in any material respect with the Term Financing Parameters established or revised by the Management Committee.

(iv) Owner shall not enter into any subsequent amendment or other modification with respect to any Term Financing that would materially increase the costs recoverable from Purchaser under this Agreement unless approved by the Management Committee.

(v) Any Impasse under this Section 5.1.2(e) shall be resolved pursuant to the arbitration provisions set forth in Section 18.3, but any such resolution shall be consistent with the terms of this Section 5.1.2(e).

Section 5.2. Budgets and Reports.

Section 5.2.1. Preliminary Budget and Schedule.

(a) Within forty-five (45) days after the Execution Date, Owner shall prepare and submit to the Management Committee for review and approval a Project Budget and Project Schedule (together, as established herein, the "Preliminary Budget and Schedule"), together with a Cost-of-Service Estimate. At the request of Purchaser's Manager, Owner shall provide the Management Committee with copies of the data, invoices, price sheets and other information utilized in the preparation of the proposed Preliminary Budget and Schedule, and shall make the personnel responsible for preparing such Preliminary Budget and Schedule available during normal business hours and upon reasonable advance notice to discuss such Preliminary Budget and Schedule with the Management Committee. At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning the Cost-of-Service Estimate.

(b) The Management Committee shall promptly review the proposed Preliminary Budget and Schedule, and may approve such Preliminary Budget and Schedule in whole or in part. If an Impasse occurs with respect to the proposed Preliminary Budget and Schedule (or any part thereof), then the Impasse shall not be resolved under the dispute resolution provisions herein, and instead, subject to Purchaser's termination rights under Section 3.3.2, the proposed Preliminary Budget and Schedule, with any changes agreed upon by the Management Committee, shall be deemed to be (i) in effect upon the commencement of the Construction Phase and (ii) approved by the Management Committee as of such date for purposes of Section 8.1.4(c)(i).

Section 5.2.2. Construction Budget and Schedule.

(a) On a quarterly basis beginning in the fourth (4th) full calendar month during the Construction Phase, but no later than the end of the fourth (4th) calendar month after the receipt by Purchaser's Manager of the most recent quarterly Construction Budget and Schedule delivered to the Management Committee under this clause (a), or as required under Section 16.3(b)(i), Owner shall prepare and submit to the Management Committee for review and approval an update of the Preliminary Budget and Schedule (such updated budget and schedule as established herein, the "Construction Budget and Schedule"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with copies of the data, invoices, price sheets and other information utilized in the preparation of the Construction Budget and Schedule, and shall make the personnel responsible for preparing the Construction Budget and Schedule available during normal business hours and upon reasonable advance notice to discuss the proposed Construction Budget and Schedule with the Management Committee.

(b) The Management Committee shall promptly review the proposed Construction Budget and Schedule, and may approve the Construction Budget and Schedule in whole or in part. If an Impasse occurs with respect to the proposed Construction Budget and Schedule (or any part thereof), then the Impasse shall not be resolved under the dispute resolution provisions herein, and instead, subject to Purchaser's termination rights under Section 3.3.6 or Section 3.3.8, as applicable, the proposed Construction Budget and Schedule, with any changes agreed upon by the Management Committee, shall be deemed to be (i) in effect upon the sixty-first (61st) day after the receipt by Purchaser's Manager of such Construction Budget and Schedule and (ii) approved by the Management Committee as of such date for purposes of Section 8.1.4(c)(i).

Section 5.2.3. Estimated Wind-Down Costs.

(a) Beginning on the date on which the first Construction Budget and Schedule is delivered to the Management Committee under Section 5.2.2 and on an annual basis thereafter concurrently with the delivery of every fourth (4th) Construction Budget and Schedule subsequently delivered to the Management Committee under Section 5.2.2, Owner shall prepare and submit to Purchaser an estimate of the Estimated Wind-Down Costs as of the Redetermination Date associated with such Construction Budget and Schedule. Owner shall provide Purchaser with access to, and copies of, all reasonably requested documentation concerning the Estimated Wind-Down Costs.

(b) If Purchaser believes that the Estimated Wind-Down Costs are incorrect or inconsistent with the standard set forth in the definition thereof, then Purchaser shall have the right to submit the matter to the Management Committee for resolution solely for the purpose of redetermining the Determined Cap during the Construction Phase, as contemplated by Section 17.1.1(d). If an Impasse occurs with respect to such matter, then the matter shall be resolved in accordance with Section 18.1(b) solely for the purpose of redetermining the Determined Cap during the Construction Phase, as contemplated by Section 17.1.1(d).

Section 5.2.4. Budget Overruns; Progress Reports.

(a) Owner shall use commercially reasonable efforts not to exceed the budgeted amounts set forth in the Preliminary Budget and Schedule or applicable Construction Budget and Schedule; provided, however, that all Project Costs (and Reconstruction Costs, if applicable) actually incurred by Owner, whether or not set forth in such Preliminary Budget and Schedule or applicable Construction Budget and Schedule, shall be recoverable under the Formula Rate in accordance with Article 8.

(b) Owner shall prepare and submit to the Management Committee for review during each calendar month during the Construction Phase a progress report for informational purposes that sets forth in reasonable detail (i) the Project Costs actually incurred in the prior month and the activities associated therewith and (ii) the current status of the milestones set forth in the Construction Budget and Schedule, including any changes in the expected timelines and the status of all Owner Approvals (collectively, the "Construction Progress Report"). At the request of Purchaser's Manager, Owner shall, or shall

cause each Contractor to, provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Construction Progress Report.

(c) Owner shall, or shall cause the principal Contractor to, notify the Management Committee promptly, but in no event later than ten (10) days, after Owner, or such Contractor, becomes aware that (i) the Commercial Operation of the Northern Pass Transmission Line is not reasonably likely to occur by the Target Date or (ii) the aggregate costs and expenses required to develop, finance, design, site, construct and Commission the Northern Pass Transmission Line and the AC Upgrades are reasonably likely to exceed either of the minimum thresholds needed for Purchaser to terminate this Agreement under Section 3.3.6.

Section 5.3. Insurance and Events of Loss.

(a) Owner shall obtain and maintain insurance of the type, in such amounts and on such terms as required by the Management Committee from time to time. Owner shall have the right, in its sole discretion, to obtain additional insurance (in amount or type) consistent with Good Utility Practice and shall acquire such insurance as may be required by any Financing Party. All premiums and other costs of property, liability or other insurance obtained by Owner in connection with the Northern Pass Transmission Line, or the ownership, development, engineering, construction or operation thereof, shall be recoverable under the Formula Rate in accordance with Article 8. Owner shall provide Purchaser with copies of certificates of all outstanding insurance obtained hereunder promptly after the receipt thereof by Owner.

(b) The Parties' rights and obligations, following a Loss Occurrence or other loss of, destruction of or damage to, or any condemnation of, the Northern Pass Transmission Line due to an event of Force Majeure, are set forth in Article 16.

Section 5.4. Compliance with Laws. At all times during the Term, the Parties shall comply with all Applicable Laws (including ISO-NE Rules to the extent applicable) and relevant Governmental Approvals and Third Party Consents.

Section 5.5. Third Party Contracts. At all times during the Term, Owner shall (a) discharge its obligations under and (b) administer all third-party contracts entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, in each case, in a commercially reasonable manner; provided, however, that Owner shall not be in breach of its obligations under the foregoing clause (a) if, due to a breach by Hydro-Québec Lender of its funding obligation under the Construction Loan Agreement, Owner fails to discharge any payment obligation under any such third-party contract. Provided that Owner has complied with its obligations under the foregoing sentence, Owner shall not be in breach of, or be liable to Purchaser under, this Agreement, and no Owner Default shall occur, as a consequence of any act or omission by any Contractor or AC Upgrade Owner, and all increased costs, expenses, fines and penalties resulting therefrom (including reasonable attorneys' fees) shall be recoverable under the Formula Rate in accordance with Article 8.

Section 5.6. Equity Commitment. Owner shall, and hereby commits to Purchaser that it will, finance a portion of the Project Costs through contributions to the equity capital of Owner in a manner consistent with Owner's obligations under Section 8.3(a). Without limiting Owner's obligations under the foregoing sentence, Owner shall enter into an equity commitment agreement with Northeast Utilities and NSTAR, and shall cause Northeast Utilities and NSTAR to enter into such equity commitment agreement with Owner, in each case, no later than the Distribution Date, pursuant to which agreement Northeast Utilities and NSTAR shall commit annually during the Construction Phase to provide, either directly or through a subsidiary, equity capital consistent with Owner's obligations under the foregoing sentence, which equity commitment is expected to be based upon the amounts set forth in the Construction Budget and Schedule for the upcoming year. The Parties acknowledge and agree that such equity commitment will be used only to finance Project Costs during the Construction Phase and may not be applied towards, or accelerated to settle, any claims resulting from an Owner Default, other than pursuant to this Section 5.6. For the avoidance of doubt, Owner's rights under such equity commitment agreement shall be part of the collateral pledged to Hydro-Québec Lender to secure Owner's obligations under the Construction Loan Agreement.

Section 5.7. Owner's Obligation to Cure; Purchaser's Losses.

(a) Owner shall use commercially reasonable efforts to cure, at its own cost and expense, any Owner Default in a commercially reasonable timeframe consistent with Good Utility Practice, and no such cost or expense shall be recoverable under the Formula Rate. For the avoidance of doubt, the foregoing sentence shall apply in the event of a delay in Commercial Operation due to an Owner Delay or in the event of a Non-Excused Outage.

(b) Neither Purchaser nor its Affiliates shall be entitled to recover from Owner any losses, damages, costs or expenses related to the Québec Line or arising under the TransÉnergie OATT, except as provided in Section 4.3.1 or Section 7.4.2.

Section 5.8. Continuity of Rights and Responsibilities. Unless otherwise agreed in writing by the Parties or prohibited by Applicable Law, the Parties shall continue to provide service and honor commitments under this Agreement and continue to make payments in accordance with this Agreement pending resolution of any bona fide Impasse or other Dispute hereunder or relating hereto.

ARTICLE 6

PROCEDURES FOR OPERATION AND MAINTENANCE OF THE NORTHERN PASS TRANSMISSION LINE

Section 6.1. Transmission Operating Agreement; ISO-NE Operational Control.

(a) Prior to entering into the Transmission Operating Agreement, Owner shall consult with the Management Committee with respect to the proposed terms and conditions thereof. The Management Committee shall promptly provide comments, if any, to Owner on such terms and conditions. Owner shall make a good faith effort to take

into account any comments made by the Management Committee that are consistent with FERC rules and policies.

(b) As of the Commercial Operation Date, Owner shall transfer operational control over the Northern Pass Transmission Line, as defined in the Transmission Operating Agreement, to Transmission Operator in accordance with the Transmission Operating Agreement. Owner shall provide, and shall direct its Affiliates to provide, such information as Transmission Operator may require to discharge its obligations under the Transmission Operating Agreement, and Owner shall comply with the instructions of Transmission Operator to the extent provided in the Transmission Operating Agreement and the ISO-NE Tariff. The Parties acknowledge and agree that Owner shall not be in breach of, or be liable to Purchaser under, this Agreement, and no Owner Default shall occur, as a consequence of Owner's compliance with such instructions of Transmission Operator; provided that Owner did not initiate or support instructions that would otherwise breach Owner's obligations under this Agreement.

Section 6.2. Good Utility Practice; Regulatory and Reliability Requirements. From and after the Commercial Operation Date, Owner shall (a) provide Firm Transmission Service and Additional Transmission Service, (b) operate and maintain the Northern Pass Transmission Line in accordance with Good Utility Practice and in compliance with all applicable regulatory requirements, including applicable NERC and NPCC reliability standards, and (c) comply with all applicable operating instructions and manufacturers' warranties. The costs associated with the discharge by Owner of its obligations under the foregoing clauses (a), (b) and (c) shall be recoverable under the Formula Rate in accordance with Article 8.

Section 6.3. Annual Plan and Operating Budget and Multiyear Outlook.

(a) No later than one hundred twenty (120) days before the start of each Contract Year or, in the case of the first Contract Year during which Owner is obligated to provide Firm Transmission Service hereunder, no later than one hundred twenty (120) days before the date Owner reasonably expects the Commercial Operation Date to occur, Owner shall deliver to the Management Committee the Annual Plan and Operating Budget for the following Contract Year, along with a non-binding Capital Plan for the following five (5) Contract Years (a "Multiyear Outlook"). Upon request by the Management Committee, Owner shall provide the Management Committee with copies of the data, invoices, price sheets and other information utilized in the preparation of any Annual Plan and Operating Budget and shall make the personnel responsible for its preparation available during normal business hours and upon reasonable advance notice to discuss the proposed Annual Plan and Operating Budget with the Management Committee. Owner shall also provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning the Multiyear Outlook.

(b) The Management Committee shall attempt to agree upon the Annual Plan and Operating Budget within sixty (60) days following its receipt thereof, and the Management Committee may approve the proposed Annual Plan and Operating Budget in whole or in part.

(i) If the Management Committee approves the Annual Plan and Operating Budget (or any part thereof) the costs associated with the approved activities shall not be subject to challenge on prudence grounds under Section 8.1.4. Notwithstanding the foregoing sentence, if the costs incurred by Owner to perform any activity in an approved Annual Plan and Operating Budget exceed, in the aggregate, the amount in the approved Annual Plan and Operating Budget for such activity, Purchaser shall then have the right to challenge the prudence of the costs that exceed such approved amount pursuant to Section 8.1.4.

(ii) If Purchaser's Authorized Representative votes against the approval of all or any part of the activities set forth in the Annual Plan and Operating Budget, and Owner nonetheless performs the unapproved activities, Purchaser shall have the right to challenge the prudence of Owner's expenditures on such unapproved activities pursuant to Section 8.1.4.

(iii) If Purchaser's Authorized Representative votes against the approval of all or any part of the activities set forth in the Annual Plan and Operating Budget, and Owner thereafter chooses not to perform activities that have not been approved, Owner's failure to undertake any such activities not approved by the Management Committee shall not constitute a violation of Good Utility Practice or a breach by Owner of its obligations hereunder with respect to any such activities, and Purchaser shall have no right to recover losses or damages from, or assert any claim against, Owner as a result of such failure. In addition, Owner shall have the right to recover from Purchaser, and Purchaser shall pay or reimburse to Owner, an amount equal to any penalties assessed by FERC, NERC or any other Governmental Authority for violations of Applicable Law by Owner, its Affiliates or any of its or their third-party contractors as a result of such failure.

(iv) In the event Owner becomes aware that the aggregate O&M Costs and Planned CapEx Costs to be incurred during any Contract Year are likely to exceed the budgeted amounts therefor, as set forth in the Annual Plan and Operating Budget, by more than fifteen percent (15%), Owner shall promptly notify the Management Committee. At the request of Purchaser's Manager, Owner shall provide the Management Committee, as applicable, with access to, and copies of, all reasonably requested documentation concerning such O&M Costs or Planned CapEx Costs.

(v) The budgeted amounts for O&M Costs and Planned CapEx Costs, as set forth in any Annual Plan and Operating Budget approved by the Management Committee or otherwise contemplated by Section 6.2, shall be used to calculate Transmission Service Payments under the Formula Rate and shall be recoverable under the Formula Rate in accordance with Article 8, subject to reconciliation, as described in Section 14.2, to account for differences between the budgeted and actual O&M Costs and Planned CapEx Costs.

(c) The Management Committee shall also attempt to agree upon the Multiyear Outlook within sixty (60) days following its receipt thereof solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d), and the Management Committee may approve the proposed Multiyear Outlook in whole or in part. If an Impasse occurs with respect to the proposed Multiyear

Outlook, then the Impasse shall be resolved in accordance with Section 18.1(b) solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d). The Capital Plan for any Contract Year shall not be deemed to be imprudent solely on the basis that such Capital Plan varied from any Multiyear Outlook that included such Contract Year. Purchaser shall not waive any right to challenge the prudence of any Capital Plan for any Contract Year solely on the basis that the Management Committee approved any Multiyear Outlook that included such Contract Year.

Section 6.4. Estimated Wind-Down Costs.

(a) Beginning on the date on which the first Annual Plan and Operating Budget is delivered to the Management Committee under Section 6.3 and thereafter concurrently with the delivery of every third (3rd) Annual Plan and Operating Budget subsequently delivered to the Management Committee under Section 6.3, Owner shall prepare and submit to Purchaser an estimate of the Estimated Wind-Down Costs as of the upcoming Redetermination Date. Owner shall provide Purchaser with access to, and copies of, all reasonably requested documentation concerning the Estimated Wind-Down Costs.

(b) If Purchaser believes that the Estimated Wind-Down Costs are incorrect or inconsistent with the standard set forth in the definition thereof, then Purchaser shall have the right to submit the matter to the Management Committee for resolution solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d). If an Impasse occurs with respect to such matter, then the matter shall be resolved in accordance with Section 18.1(b) solely for the purpose of redetermining the Determined Cap during the Operation Phase, as contemplated by Section 17.1.1(d).

Section 6.5. Scheduled Maintenance. Unless approved by the Management Committee, or unless the Transmission Operator or TransÉnergie requires otherwise, Owner shall not perform or otherwise undertake, and shall cause third parties not to perform or otherwise undertake, any scheduled maintenance or capital project with respect to the Northern Pass Transmission Line that requires any interruption or reduction of scheduling rights over the Northern Pass Transmission Line during the months of January, February, March, June, July, August, September and December.

Section 6.6. Extraordinary Capital Expenditures.

(a) In the event Owner determines that any Extraordinary CapEx is required, Owner shall promptly notify the Management Committee and deliver to it information relating to the cost and expected scope and nature of the Extraordinary CapEx, including any expected outages and overhauls of the Northern Pass Transmission Line associated therewith (the "Extraordinary CapEx Plan"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Extraordinary CapEx Plan.

(b) The Management Committee shall attempt to agree upon any Extraordinary CapEx Plan as soon as practicable after its receipt thereof, and the Management Committee may approve the proposed Extraordinary CapEx Plan in whole or in

part; provided, however, that, subject to Purchaser's rights under Section 8.1.4, no Management Committee approval shall be required for any Extraordinary CapEx Plan that does not exceed One Million Dollars ($1,000,000).

(c) Section 6.3(b)(i), Section 6.3(b)(ii) and Section 6.3(b)(iii) shall apply *mutatis mutandis* to costs incurred by Owner to perform Extraordinary CapEx that is approved or not approved by the Management Committee.

(d) Any Extraordinary CapEx Plan shall be used to calculate Transmission Service Payments under the Formula Rate and the costs set forth therein shall be recoverable under the Formula Rate in accordance with Article 8, subject to reconciliation, as described in Section 14.2, to account for differences between the budgeted and actual Extraordinary CapEx Costs.

Section 6.7. Record of Management Committee Decisions. The minutes for any meeting at which a vote was held with respect to a proposed Annual Plan and Operating Budget or Extraordinary CapEx Plan, as applicable, or any unanimous written consent in lieu thereof, shall expressly set forth in reasonable detail the grounds on which Purchaser's Authorized Representative disapproved of any maintenance or capital expenditure set forth in such Annual Plan and Operating Budget or Extraordinary CapEx Plan, as applicable, and the reasons therefor.

ARTICLE 7

PURCHASER'S TRANSMISSION RIGHTS OVER THE NORTHERN PASS TRANSMISSION LINE

Section 7.1. Transmission Service.

Section 7.1.1. Firm Transmission Service. Owner shall make available to Purchaser, from and after the Commercial Operation Date, transmission capacity on the Northern Pass Transmission Line in order to deliver electrical energy, as scheduled by Purchaser or by a third party under the resale provisions of Article 10, in an amount equal to the Contract Capacity ("Firm Transmission Service"). Firm Transmission Service shall be made available over the Northern Pass Transmission Line at any time from and after the Commercial Operation Date, in a north-to-south and south-to-north direction, between the U.S. Border and the Delivery Point. Firm Transmission Service shall be subject to curtailment or interruption only as a result of an Excused Outage or as provided in Section 15.3(b). Without limiting Owner's obligations under this Section 7.1.1, the quantity of Firm Transmission Service that Owner will provide in any hour shall not exceed the Total Transfer Capability for such hour.

Section 7.1.2. Additional Transmission Service. To the extent (a) transmission capacity in excess of the Contract Capacity in a north-to-south or south-to-north direction is necessarily incidental to the design, engineering, construction or operation of the Northern Pass Transmission Line, as described in this Agreement, and (b) ISO-NE permits the scheduling of transmission service using such incidental transmission capacity during any hour (or such other permissible scheduling period adopted by ISO-NE), then Owner shall make

available to Purchaser, from and after the Commercial Operation Date, non-firm transmission service in an amount equal to such incidental transmission capacity ("Additional Transmission Service"). Additional Transmission Service shall be subject to curtailment or interruption by ISO-NE in accordance with the ISO-NE Tariff or upon determination by the Management Committee that the provision of the Additional Transmission Service would degrade the provision of Firm Transmission Service. For the avoidance of doubt, the unavailability of, or any curtailment or interruption in, all or any portion of Additional Transmission Service shall not constitute an Excused Outage under Section 7.3 or Non-Excused Outage under Section 7.4, and any such unavailability, curtailment or interruption shall not affect the calculation of the size of any Excused Outage under Section 7.3 or Non-Excused Outage under Section 7.4.

Section 7.1.3. Limitation on Transmission Service. Owner shall have no obligation to provide transmission service under this Agreement other than Firm Transmission Service and Additional Transmission Service. Purchaser shall have no right to redirect service to alternate points of delivery or receipt on any portion of the transmission system operated by ISO-NE other than the Northern Pass Transmission Line.

Section 7.1.4. Scheduling. All Firm Transmission Service and Additional Transmission Service shall be scheduled in accordance with the rules relating to the scheduling of electrical energy or capacity transactions over the Northern Pass Transmission Line, as established under the Transmission Operating Agreement (the "Scheduling Rules").

Section 7.1.5. Owner's Cooperation.

(a) Without limiting the generality of Owner's express obligations under Section 7.1.1 and Section 7.1.2, but subject to the limitations provided in Section 11.2(c), to the extent permitted by the FERC Authorization and ISO-NE Rules and consistent with Good Utility Practice, at Purchaser's reasonable request, Owner shall cooperate with Purchaser and ISO-NE in order to permit Purchaser to realize the full reliability and economic benefits intended under this Agreement.

(b) Owner shall provide Purchaser with notice of any FERC regulatory proceedings to which Owner is a party promptly after Owner becomes aware of any such proceeding. Owner shall not take any position in such proceeding that is inconsistent with its obligations under this Agreement.

Section 7.2. Damages Under Third Party Contracts.

(a) Subject to the rights of any Financing Party, if and to the extent Owner receives or is entitled to receive damages, whether liquidated or otherwise, or other amounts payable in connection with a third party's breach of its obligations under, or termination (for whatever reason) of, any Construction Contract (including any Construction Contract with Hydro-Québec Contractor) or other contract (including any contract with the OASIS Administrator) entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, Owner shall credit the amounts received by Owner to Purchaser under the Formula Rate, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with the receipt and final collection of such amounts.

(b) Owner shall use commercially reasonable efforts to pursue the collection or recovery of any such amounts and otherwise seek to enforce its rights under any Construction Contract (including any Construction Contract with Hydro-Québec Contractor), insurance policy or other third-party contract (including any contract with an Affiliate of Northeast Utilities or NSTAR) entered into by Owner in connection with the Northern Pass Transmission Line or the AC Upgrades.

Section 7.3. Excused Outages or Reductions.

(a) Notwithstanding anything herein to the contrary, Owner shall not be in breach of, or be liable to Purchaser for any losses or damages under, this Agreement, and no Owner Default shall occur, as a consequence of an Excused Outage. "Excused Outages" means any outages of the Northern Pass Transmission Line or reductions in the Total Transfer Capability below the Contract Capacity (whether as a result of a physical condition, legal impediment or otherwise), if and to the extent due to any reason other than Owner's failure to (i) exercise Good Utility Practice or (ii) otherwise discharge its obligations under this Agreement.

(b) For the avoidance of doubt, Excused Outages shall include outages of the Northern Pass Transmission Line or reductions in the Total Transfer Capability below the Contract Capacity due to the following events, but only to the extent they satisfy the definition set forth in last sentence of clause (a) above:

(i) Events of Force Majeure;

(ii) Scheduled maintenance, if and to the extent required to discharge Owner's obligations under Section 6.2 or Section 5.4 and consistent with Owner's obligations under Section 6.5;

(iii) Outages or reductions in the use or availability of transmission lines other than the Northern Pass Transmission Line;

(iv) Decisions of TransÉnergie or conditions in the electric system located in the Province of Québec, including the unavailability of the Québec Line, in whole or in part; and

(v) Decisions of ISO-NE, including a decision to reduce or suspend the scheduling rights over the Northern Pass Transmission Line as a result of any grid reliability issue or to preserve facilities and equipment from physical damage.

(c) Purchaser shall be obligated, during any Excused Outage, to pay the Transmission Service Payment in accordance with Article 8 and Article 14 to the same extent as if such Excused Outage had not occurred, except as provided in Section 16.4 for any Extended Outage. Owner shall use commercially reasonable efforts to (i) seek to avoid and (ii) mitigate or remedy any Excused Outage in a commercially reasonable timeframe consistent with Good Utility Practice.

Section 7.4. Non-Excused Outages or Reductions.

Section 7.4.1. Reduction in Transmission Service Payments. Unless otherwise excused under Section 7.3 or Article 16, if and to the extent an outage of the Northern Pass Transmission Line or reduction in the Total Transfer Capability below the Contract Capacity (whether as a result of a physical condition, legal impediment or otherwise) is due to Owner's failure to (a) exercise Good Utility Practice or (b) otherwise discharge its obligations hereunder (a "Non-Excused Outage"), the Transmission Service Payment for such period shall be reduced by an amount that bears the same ratio to the Transmission Service Payment as the amount of unavailable transmission capacity resulting from such Non-Excused Outage bears to the Contract Capacity and Owner shall have no right to recover such amounts. Any Dispute over whether or not or to what extent a Non-Excused Outage has occurred shall be resolved in accordance with Article 18. For the avoidance of doubt, pending resolution of any such Dispute, Purchaser's right, pursuant to this Section 7.4.1, to any reduction in the Transmission Service Payments shall be suspended.

Section 7.4.2. Québec Damages. In addition to the reduction in Transmission Service Payments contemplated by Section 7.4.1, Purchaser shall have the right to recover from Owner, and Owner shall pay or reimburse to Purchaser, for each month (or part thereof) of any Non-Excused Outage, an amount equal to the OATT Payment with respect to such month (or part thereof) or, to the extent Purchaser acquires replacement transmission service during such month (or part thereof), the Replacement Transmission Cost for the replaced transmission capacity, if less expensive than such OATT Payment (the "Québec Damages"); provided, however, that Owner's liability to Purchaser for any Québec Damages shall not commence unless and until such time as the aggregate amount of unavailable transmission capacity resulting from Non-Excused Outages (which amount shall be converted to, and expressed in, megawatt-hours) exceeds the Initial Allowance in any Contract Year; provided, further, however, that, with respect to any Non-Excused Outage, Owner's maximum liability to Purchaser for any Québec Damages that are related to such Non-Excused Outage (regardless of the duration of such Non-Excused Outage) shall not exceed, in the aggregate, an amount equivalent to the sum of the OATT Payments for the period commencing on the later to occur of (i) the first date of such Non-Excused Outage and (ii) the date on which the aggregate amount of unavailable transmission capacity that is attributable to Non-Excused Outages (expressed in megawatt-hours) exceeds the Initial Allowance in any Contract Year and ending six (6) months thereafter or upon the earlier termination of this Agreement pursuant to its terms. Any such Québec Damages, when taken as a whole, shall not exceed the amounts that would have been owed by a Person other than an Affiliate of TransÉnergie in a comparable arm's-length transaction or arrangement under the TransÉnergie OATT. Purchaser shall use commercially reasonable efforts to cause HQP to mitigate the amount of any Québec Damages. At Owner's reasonable request, Purchaser shall make available to Owner any information reasonably necessary to support the amounts owed to Purchaser by Owner pursuant to this Section 7.4.2.

Section 7.4.3. Liquidated Damages. The Parties acknowledge and agree that the modification of Purchaser's payment obligations pursuant to Section 7.4.1 and the payment of amounts by Owner to Purchaser under Section 7.4.2 are an appropriate remedy and that any such modification or payment does not constitute a forfeiture or penalty of any kind. The Parties further acknowledge and agree that the damages for a Non-Excused Outage are

difficult or impossible to determine and that the damages calculated hereunder constitute a reasonable approximation of the harm or loss to Purchaser as a result thereof.

Section 7.4.4. Sole and Exclusive Remedy. Subject to the discharge by Owner of its obligations under Section 5.7(a), the rights provided in Section 3.3.12 and this Section 7.4 shall collectively be the sole and exclusive remedy of Purchaser with respect to a Non-Excused Outage. The foregoing sentence shall not be construed in any way to limit (a) Purchaser's right to recover any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover any amounts owed to Purchaser by Owner under this Agreement, (b) Purchaser's rights and remedies under the Purchaser's Security Documents or Owner Guaranty or against Purchaser's Lien or any other financial assurances held by Purchaser or (c) Purchaser's right to recover payment of any indemnification obligations of Owner to Purchaser pursuant to Section 21.2.

Section 7.5. Metering. Metering and telemetering requirements for the Northern Pass Transmission Line shall be established by the Management Committee in accordance with Good Utility Practice and as necessary to (a) accomplish the purposes of, and to implement and administer, this Agreement and (b) satisfy the requirements of, and to implement and administer, the Interconnection Agreement and the Transmission Operating Agreement. If an Impasse occurs with respect to such metering and telemetering requirements, then the matter shall be resolved in accordance with Section 18.1(b). All costs incurred by Owner in connection with metering and telemetering for the Northern Pass Transmission Line shall be recoverable under the Formula Rate in accordance with Article 8.

ARTICLE 8

PAYMENT FOR TRANSMISSION SERVICE OVER THE NORTHERN PASS TRANSMISSION LINE

Section 8.1. Transmission Service Payment; Application of Formula Rate.

Section 8.1.1. Letter Agreement. In the event this Agreement is terminated under Section 3.3.2, Owner's right to recover from Purchaser any costs or expenses incurred by Owner in connection with the Northern Pass Transmission Line shall be as provided in the Letter Agreement and subject to FERC approval, and Purchaser shall have no obligation for any charges under this Agreement (other than as provided in the Letter Agreement).

Section 8.1.2. Charges under the Formula Rate.

(a) Prior to the Commercial Operation Date, Owner shall not invoice Purchaser for any Transmission Service Payments hereunder.

(b) From and after the Commercial Operation Date, unless expressly excluded under the terms and conditions of this Agreement, Purchaser shall pay all charges, as calculated pursuant to the Formula Rate, which charges shall be payable on a monthly basis in accordance with Article 14 (the "Transmission Service Payment"). Owner shall not invoice Purchaser for, and Purchaser shall have no obligation to pay, any charges that

are not recoverable under the Formula Rate, except (i) as contemplated by Section 8.1.1, (ii) for amounts owed to Owner by Purchaser under Section 3.3, Section 3.4, Section 9.3.3(c), Section 9.3.4 or Section 9.3.5(d), (iii) for damages that may be recovered by Owner under this Agreement as a result of a Purchaser Default, (iv) for any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Owner to recover any amounts owed to Owner by Purchaser under this Agreement or to secure the release of Purchaser's Lien and the Purchaser's Security Documents or other security or performance assurance provided by or on behalf of Owner after the later to occur of the end of the Term or the date on which any accrued but unpaid payment obligation of Owner to Purchaser hereunder shall have been fully, finally and indefeasibly satisfied, (v) for fees and expenses reasonably incurred by Owner in enforcing Purchaser's participation obligation pursuant to Section 18.3.5, or (vi) for payment of any indemnification obligations of Purchaser to Owner pursuant to Section 21.1.

(c) Transmission Service Payments calculated under the Formula Rate shall be based upon a projected cost-of-service calculation. The Formula Rate shall be reconciled with actual costs on an annual basis in accordance with Section 14.2.

(d) If and when the Construction Phase occurs, the Letter Agreement shall terminate immediately without further action of the Parties, and commencing on the Commercial Operation Date, (i) all Construction Costs incurred during the Development Phase shall be included in the Formula Rate, together with AFUDC, as accrued thereon in accordance with clause (e)(ii) below, but subject to Section 4.3.1, and (ii) all Pre-COD Expenses shall be included in the Formula Rate, together with Carrying Charges, as accrued thereon in accordance with clause (e)(iii) below, but subject to Section 4.3.1.

(e) For purposes of calculating the Transmission Service Payment under the Formula Rate, (i) depreciation shall not be included before the Commercial Operation Date; (ii) AFUDC shall be accrued on all capital costs that were incurred during the Development Phase and Construction Phase and that are recoverable under the Formula Rate, such that recovery of a return on such capital costs, together with AFUDC accrued thereon, shall commence on the Commercial Operation Date (except as otherwise contemplated in Section 3.3 with respect to the recovery of costs and AFUDC following termination of this Agreement); and (iii) commencing on the date on which the Development Phase begins, Owner shall establish a regulatory asset that will include all Pre-COD Expenses, together with carrying charges on the regulatory asset at Owner's weighted cost of capital (as calculated under the Formula Rate) ("Carrying Charges") from the date on which the regulatory asset is established until the regulatory asset is fully amortized, and shall amortize such regulatory asset over a three (3)-year period commencing on the Commercial Operation Date.

(f) Owner shall seek FERC approval or acceptance to permit Owner to include in the regulatory asset described in clause (e)(iii) above all AC Upgrade Costs associated with the AC Upgrades placed-in-service before the Commercial Operation Date.

Section 8.1.3. Purchaser's Costs. Except as expressly contemplated by this Agreement for (a) any damages suffered by Purchaser as a result of an Owner Default, (b) any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to

recover any amounts owed to Purchaser by Owner under this Agreement or to secure the release of any Purchaser Guaranty or other security or performance assurance provided by or on behalf of Purchaser after the later to occur of the end of the Term or the date on which any accrued but unpaid payment obligation of Purchaser to Owner hereunder shall have been fully, finally and indefeasibly satisfied, (c) fees and expenses reasonably incurred by Purchaser in enforcing Owner's participation obligation pursuant to Section 18.3.5 or (d) any indemnification obligations of Owner to Purchaser pursuant to Section 21.2, Owner shall have no liability to Purchaser or its Affiliates for any costs, expenses or charges incurred by Purchaser in connection with this Agreement.

Section 8.1.4. Challenges to Inclusion of Charges under the Formula Rate. Owner's right to recover any costs or expenses under the Formula Rate, and Purchaser's liability for such costs or expenses under this Agreement, shall be subject to the following provisions:

(a) The Formula Rate shall only include costs and expenses that were prudently incurred; provided that a rebuttable presumption shall exist that all costs and expenses included in the Formula Rate were prudently incurred, and nothing contained herein shall be construed to alter the burdens of proof and going forward, as set forth in clause (b) below.

(b) Subject to Section 18.2, Purchaser shall have the right to challenge the prudency of any costs or expenses that Owner seeks to recover from Purchaser under this Agreement by filing a pleading with FERC seeking to omit from the Transmission Service Payments calculated under the Formula Rate any costs or expenses included in the Formula Rate that were not prudently incurred. Such prudency challenge shall be made pursuant to Sections 306 and 309 of the Federal Power Act to invoke FERC's retained authority to investigate and order refunds with respect to any imprudent charges sought to be recovered under the Formula Rate. Any proceeding initiated by Purchaser to challenge the prudency of Owner's costs and expenses shall be conducted using the same standards and in accordance with the same procedures that FERC would normally apply to prudency challenges. Further, a rebuttable presumption shall exist that all costs and expenses included in the Formula Rate were prudently incurred; provided, however, that once Purchaser has met its initial burden to show that a cost or expense was not prudently incurred, the burden shall then shift back to Owner to prove that such cost or expense was prudently incurred. The Parties specifically intend and acknowledge and agree that, if FERC determines that any amount included in the Formula Rate was not prudently incurred, then such amount may be excluded from the Formula Rate effective as of the date such amount was first included in Owner's FERC account(s) that comprise the Formula Rate.

(c) Notwithstanding clauses (a) and (b) above, Purchaser acknowledges and agrees that no prudency challenge shall be permitted with respect to (i) any cost or expense to the extent approved by the Management Committee, including pursuant to Section 5.2.1(b), Section 5.2.2(b), Section 5.3(a), Section 6.3(b), Section 6.6(b), Section 9.3.2(b), Section 16.3(b) and Section 16.3(c), but excluding Section 5.2.3, Section 6.3(c) or Section 6.4, or agreed to in writing by Purchaser or (ii) any cost or expense established pursuant to the arbitration provisions set forth in Section 18.3, other than any cost or expense so established as a result of an Impasse under Section 5.2.3, Section 6.3(c) or Section 6.4.

Purchaser further acknowledges and agrees that its right to challenge any costs under this Section 8.1.4 shall be subject to Section 14.3(b).

(d) Subject to Section 5.5 and Section 6.3(b)(iii), in no event shall any (i) penalties assessed by FERC, NERC or any other Governmental Authority for any violation of Applicable Law by Owner, its Affiliates or any of its or their third-party contractors or (ii) payments made to settle allegations of such violations be recoverable under the Formula Rate, unless the Management Committee shall have approved, or Purchaser shall have agreed in writing to reimburse Owner for, such amounts.

(e) This Section 8.1.4 shall not be construed in any way to limit any other rights Purchaser may have to file for relief with FERC pursuant to Section 18.2.

Section 8.1.5. Challenges to Application of Formula Rate. If, as a result of the audit of Owner's application of the Formula Rate or for any other reason, Purchaser believes that Owner has miscalculated or incorrectly included charges under the Formula Rate, Purchaser shall then have the right to submit the matter to the Management Committee for resolution under Section 18.1(a). If an Impasse occurs with respect to such matter, Purchaser shall then have the right to file a complaint with FERC seeking an order requiring Owner to comply with the Formula Rate, as its filed tariff.

Section 8.2. Service Life. For purposes of calculating the Transmission Service Payments under the Formula Rate, (a) the depreciable life of any depreciable asset comprising part of the Northern Pass Transmission Line as of the Commercial Operation Date shall be equal to forty (40) years, and (b) the depreciable life of a capital addition that is placed-in-service after the Commercial Operation Date shall be equal to the lesser of (i) its economic life and (ii) the remaining Term as of the placed-in-service date.

Section 8.3. Capital Structure.

(a) From and after the Development Phase, Owner shall use commercially reasonable efforts to maintain a Capital Structure equal to 50-50.

(b) Notwithstanding clause (a) above, at all times during the Term, the Capital Structure for purposes of calculating Transmission Service Payments under the Formula Rate shall be equal to 50-50.

Section 8.4. Return on Equity.

(a) The return on equity ("ROE") used in the Formula Rate to accrue AFUDC prior to the Commercial Operation Date and to calculate the weighted cost of capital for the Carrying Charges on the regulatory asset established pursuant to Section 8.1.2(e)(iii) shall be twelve and fifty-six one-hundredth percent (12.56%).

(b) Upon Commercial Operation, the ROE shall be adjusted to equal (i) the Base ROE, plus (ii) an adder equal to the lesser of (A) one hundred forty-two (142) basis points and (B) an amount that would not cause the total ROE to exceed the applicable zone of reasonableness for such Regional Transmission Service, as established in the most

recent rate order for such service. In the event the Base ROE for Regional Transmission Service using the transmission facilities of Northeast Utilities or NSTAR is no longer based upon a single, regional Base ROE, Owner shall make a filing under Section 205 of the Federal Power Act to establish the ROE applicable to service under this Agreement that includes the adder set forth above; provided, however, that Owner shall delay such FERC filing for a period not less than thirty (30) days, but not to exceed sixty (60) days, to provide time for the Parties to negotiate the ROE to be applicable to service under this Agreement. The Parties acknowledge and agree that Purchaser shall have the right to challenge any FERC filing made under Section 205 of the Federal Power Act with respect to a replacement for the Base ROE, unless Purchaser shall have agreed in writing to the ROE set forth in such filing.

Section 8.5. Cost Recovery of AC Upgrades.

(a) The Parties acknowledge and agree that the AC Upgrades will be constructed and owned by the AC Upgrade Owners. Owner shall enter into a facilities agreement with each such AC Upgrade Owner to pay the costs to design, license, construct and operate such AC Upgrades (each, a "Facilities Agreement").

(b) Prior to executing any Facilities Agreement, Owner shall consult with the Management Committee with respect to the proposed terms and conditions thereof. The Management Committee shall promptly provide comments, if any, to Owner on such terms and conditions. Owner shall make a good faith effort to take into account any comments made by the Management Committee that are consistent with FERC rules and policies. Any Facilities Agreement entered into with an Affiliate of Northeast Utilities or NSTAR shall be on terms and conditions at least as favorable to Owner, when taken as a whole, as would have been obtained (at the time entered into) in a comparable arm's-length transaction or arrangement with a Person other than an Affiliate of Northeast Utilities or NSTAR; provided, however, that, if such transaction or arrangement has been accepted or approved by FERC or any other Governmental Authority that specifically reviews the Affiliate relationship in such transaction or arrangement, then such transaction or arrangement shall be deemed to be a comparable arm's-length transaction or arrangement.

(c) All amounts incurred by Owner under the Facilities Agreement ("AC Upgrade Costs") shall be recovered as expenses under the Formula Rate in accordance with Article 8. Notwithstanding the foregoing sentence, the AC Upgrade Costs under any Facilities Agreement entered into with an Affiliate of Northeast Utilities or NSTAR shall not exceed the costs and expenses that would have been incurred by Owner if the AC Upgrade Costs were directly incurred by Owner and recovered pursuant to the Formula Rate in accordance with this Agreement.

(d) Owner shall coordinate with the AC Upgrade Owners and ISO-NE as necessary to obtain for Purchaser the Other Transmission Rights under the ISO-NE Tariff that are associated with, or issued in connection with, the AC Upgrades, the costs of which AC Upgrades are incurred by Owner and recovered from Purchaser in accordance with this Agreement.

(e) In the event ISO-NE determines that all or any portion of the AC Upgrade Costs are eligible to be included in Regional Rates, Purchaser shall have the right, exercisable in its sole discretion, to continue to bear responsibility under this Agreement for all or any portion of the AC Upgrade Costs, in which case Purchaser shall continue to be entitled, in accordance with the ISO-NE Tariff, to all or any portion of the Other Transmission Rights that are associated with, or issued in connection with, Purchaser's continued responsibility for such AC Upgrade Costs.

Section 8.6. Transfer and Cost Recovery of AC Line.

(a) The AC Line shall be initially owned by Owner. AFUDC or Carrying Charges, as applicable, shall be accrued on the costs and expenses that are incurred by Owner in connection with the AC Line in accordance with Section 8.1.2(e)(ii) or Section 8.1.2(e)(iii), and, commencing on the Commercial Operation Date, such costs and expenses, together with AFUDC or Carrying Charges, as applicable, accrued thereon, shall be recoverable under the Formula Rate (i) in the same manner as the costs and expenses that are incurred by Owner in connection with the HVDC Line and (ii) otherwise in accordance with Article 8, except, in each case, as otherwise provided in clause (e) below.

(b) In the event all or any portion of the AC Line, for all or any part of the Term, meets the criteria for Pool Transmission Facilities ("PTF") (as those criteria and term are defined in the ISO-NE Tariff), Owner shall have the right, in its sole discretion, to transfer ownership of any such PTF portion of the AC Line to its Affiliate, PSNH, in accordance with this Section 8.6.

(c) In connection with any such transfer of ownership, Owner shall enter into an agreement with PSNH ("AC Line Agreement") pursuant to which Owner shall, subject to clause (e) below, (i) pay all costs and expenses (including unrecovered return on capital investment) that (A) have been or will be incurred in connection with such transferred portion of the AC Line, (B) have not been previously recovered under this Agreement, and (C) are not and will not be included in Regional Rates. To the extent not included in Regional Rates, such costs and expenses shall include those necessary for Purchaser's eligibility, in accordance with the ISO-NE Tariff, for the Other Transmission Rights that are associated with, or issued in connection with, the AC Line. Pursuant to the AC Line Agreement, Owner shall acquire sufficient rights with respect to such PTF portion of the AC Line to permit Owner to discharge its obligations under this clause (c) and Purchaser to exercise its rights under clause (f) below.

(d) Purchaser shall have the right to participate in the negotiation of the AC Line Agreement, and the Parties shall attempt to reach agreement on the rates, terms and conditions thereof, consistent with the parameters set forth in this Section 8.6. In the event the Parties fail to reach agreement with PSNH on the rates, terms and conditions of the AC Line Agreement within sixty (60) days following the commencement of such negotiations, Owner shall unilaterally file the AC Line Agreement with FERC in unexecuted form pursuant to Section 205 of the Federal Power Act, and Purchaser shall have the right to contest any of the rates, terms and conditions thereof, consistent with the parameters set forth in this Section 8.6, or to seek changes to the AC Line Agreement pursuant to Section 206 of the

Federal Power Act, consistent with the parameters set forth in this Section 8.6. Except as provided in the foregoing sentence, and consistent with the terms of clause (b) above, Purchaser shall not have the right to oppose the transfer by Owner of ownership of any PTF portion of the AC Line to PSNH.

(e) All amounts incurred by Owner under the AC Line Agreement shall be recovered as expenses under the Formula Rate in accordance with Article 8. Notwithstanding the foregoing sentence, such amounts shall not exceed the costs and expenses that would have been incurred by Owner if the AC Line were still owned by Owner and such amounts were recovered pursuant to the Formula Rate in accordance with this Agreement. In no event shall Owner have the right to recover any return on investment associated with any PTF portion of the AC Line transferred to PSNH that is higher than the ROE established in Section 8.4.

(f) Upon a reasoned basis, Purchaser may request that Owner or PSNH, whichever is the owner of the AC Line (such party, "AC Line Owner"), determine and inform Purchaser of whether or not the costs and expenses associated with all or any portion of the AC Line should be included in Regional Rates. If AC Line Owner determines that such Regional Rate treatment is consistent with AC Line Owner's obligations and representations to FERC, other Governmental Authorities and AC Line Owner's Affiliates, then AC Line Owner shall submit such request to ISO-NE within ninety (90) days after the receipt by Owner of the request described in the first sentence of this clause (f). If ISO-NE subsequently determines that the costs and expenses associated with all or any portion of the AC Line are eligible to be included in Regional Rates, then Purchaser shall have the right, exercisable in its sole discretion, to take either of the following actions:

(i) Accept such Regional Rate treatment; or

(ii) Continue to bear responsibility under this Agreement for all or any portion of the costs and expenses associated with the transferred portion of the AC Line, in which case Purchaser shall be entitled, in accordance with the ISO-NE Tariff, to all or any portion of the Other Transmission Rights that are associated with, or issued in connection with, Purchaser's continued responsibility for such costs and expenses.

Owner and its Affiliates assume no obligations under this Agreement to advocate, with ISO-NE, NEPOOL or otherwise, for the Regional Rate treatment of all or any portion of the AC Line, and neither Owner nor its Affiliates shall have any liability to Purchaser if all or any portion of the AC Line does not receive such Regional Rate treatment. If AC Line Owner determines that it will not submit or support a request to ISO-NE for such Regional Rate treatment, then Owner shall notify Purchaser in writing of such decision within ninety (90) days after the receipt by Owner of the request described in the first sentence of this clause (f). Following the end of such ninety (90)-day period, Purchaser shall have the right to file a complaint with FERC seeking an order requiring such Regional Rate treatment.

(g) From and after the transfer to PSNH of those portions of the AC Line designated as PTF by ISO-NE, the following provisions shall apply for all purposes under this Agreement for the remainder of the Term:

(i) If the entirety of the AC Line has been designated PTF and transferred to PSNH, then the Delivery Point shall be the southern terminus of the HVDC Line at the DC/AC converter station located near the Webster substation in the City of Franklin in the State of New Hampshire, and if less than the entirety of the AC Line has been designated as PTF, then the Management Committee shall determine the appropriate Delivery Point;

(ii) References to the Northern Pass Transmission Line shall exclude all portions of the AC Line that have been designated as PTF;

(iii) References to the AC Upgrades, other than references thereto in Section 8.5, shall include the portions of the AC Line that have been designated as PTF;

(iv) Transmission service over the portions of the AC Line designated as PTF shall be provided in accordance with Section II of the ISO-NE Tariff and not pursuant to the terms and conditions of this Agreement; and

(v) Owner shall continue to maintain the Northern Pass Transmission Line to the same standard, in accordance with Section 6.2 and Section 6.3, as existed before the Delivery Point was changed.

ARTICLE 9

RIGHTS UPON EXPIRATION OF TERM

Section 9.1. Rollover Rights.

(a) Unless this Agreement is terminated early under Section 3.3, Section 15.3 or Section 15.4, Purchaser shall have rollover rights at the end of the initial Term in accordance with Order No. 890 *et seq.* and the FERC pro forma open access transmission service tariff, as such rights are defined as of the Effective Date.

(b) If Purchaser chooses to exercise rollover rights in accordance with clause (a) above, Owner shall then prepare and deliver to Purchaser, no later than six months after such exercise, an engineering assessment, which shall include an assessment of (i) the ability of the Northern Pass Transmission Line to operate for the proposed extended Term, (ii) any upgrades or refurbishment required to support the operation of the Northern Pass Transmission Line for the proposed extended Term, and (iii) forecasted capital expenditures over the proposed extended Term. All costs and expenses incurred by Owner in connection with such engineering assessment shall be recoverable under the Formula Rate in accordance with Article 8. If such engineering assessment indicates that the Northern Pass Transmission Line is incapable of providing Firm Transmission Service for the full duration of the extended Term requested by Purchaser or if the costs required to support the operation of the Northern Pass Transmission Line for the proposed extended Term are unacceptable to Purchaser, in its sole discretion, then Purchaser shall have the right, exercisable in its sole

discretion, to (A) revise its election to reduce the period of the extended Term or (B) waive its rollover rights.

(c) Owner shall not enter into any contract or other arrangement for a Subsequent Use that is inconsistent with Purchaser's rollover rights, as provided herein.

Section 9.2. Reimbursement of Capital Costs. If, following the expiration or earlier termination of the Term, (a) a third party acquires service over the Northern Pass Transmission Line, or (b) the Northern Pass Transmission Line is included in Regional Rates (either event, a "Subsequent Use"), then Owner shall reimburse Purchaser for a pro rata portion of the costs and expenses associated with each capital addition comprising part of the Northern Pass Transmission Line that has an expected useful life beyond the end of the Term, as determined using the ratio of (i) the period of time during which such third party acquires service over the Northern Pass Transmission Line or, if ISO-NE includes the Northern Pass Transmission Line in Regional Rates, the remaining useful life of the Northern Pass Transmission Line following the end of the Term, and (ii) such period of time or remaining useful life, as applicable, plus the amortization period used to charge Purchaser for such capital addition. No later than thirty (30) days after Owner has entered into any contract or other arrangement for a Subsequent Use, Owner shall (A) calculate the reimbursement amount with respect to such contract or other arrangement, (B) provide a copy of such calculation to Purchaser, and (C) pay to Purchaser any amounts owed by Owner to Purchaser under this Section 9.2, together with interest thereon calculated pursuant to Section 14.5(a), in a single lump sum and in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. Any Dispute with respect to the amount owed to Purchaser under this Section 9.2 shall be resolved in accordance with Article 18.

Section 9.3. Retirement and Decommissioning.

Section 9.3.1. Establishment of Regulatory Asset; Recovery of Net Decommissioning Costs.

(a) In the event all or a portion of the Northern Pass Transmission Line is required to be Decommissioned by Applicable Law, Owner shall establish the Regulatory Asset – Asset Retirement Obligation (Decommissioning), as defined in Attachment B. At the time Owner files this Agreement with FERC pursuant to Section 2.1(a), Owner shall also seek FERC approval or acceptance to permit Owner to establish such regulatory asset.

(b) Unless this Agreement is terminated prior to the expiration of the Term under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3 (in which case Section 9.3.3(c) shall apply) or under Section 3.3.7 or Section 15.4 (in which case Section 9.3.3(d) shall apply), promptly after the Decommissioning Plan is approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), Owner shall calculate the Levelized Monthly Decommissioning Payment. The "Levelized Monthly Decommissioning Payment" shall be

equal to (i) the estimated Net Decommissioning Costs, as set forth in such Decommissioning Plan (which estimated Net Decommissioning Costs shall be expressed in dollars for the year(s) during which they are expected to be incurred and then discounted to the present value at the beginning of the first calendar day after the end of the Decommissioning Payment Period (regardless of whether or not such day is a Business Day) using a discount factor equal to the reasonably expected monthly rate of return applied in computing the Levelized Monthly Decommissioning Payment), multiplied by (ii) the Decommissioning Payment Formula. An example of this calculation is set forth in Attachment H. Thereafter, the Levelized Monthly Decommissioning Payment shall not be subject to change (unless such change shall have been agreed by the Parties or approved by the Management Committee).

(c) Owner shall have the right to make a unilateral filing under Section 205 of the Federal Power Act to establish a separate rate for the recovery of Net Decommissioning Costs consistent with this Section 9.3, rather than to recover such Net Decommissioning Costs under the Formula Rate, and Purchaser shall have the right to challenge such filing, unless Purchaser shall have agreed in writing on such filing.

Section 9.3.2. Decommissioning Plan.

(a) No later than six (6) months before the commencement of the Decommissioning Payment Period, or if this Agreement is earlier terminated under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3, no later than sixty (60) days after such termination, Owner shall deliver to the Management Committee a statement that sets forth in reasonable detail (i) Owner's estimation of (A) the Decommissioning Costs and Salvage Proceeds and, unless this Agreement is terminated early under Section 3.3 or Section 15.3, the Levelized Monthly Decommissioning Payment derived therefrom, and (B) any activities associated with either thereof and (ii) the scope and frequency of informational progress reports with respect to the Decommissioning of the Northern Pass Transmission Line, including the process for the recovery by Owner of its actual Net Decommissioning Costs following the exhaustion of the Decommissioning Fund prior to the completion of Decommissioning (collectively, the "Decommissioning Plan"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Decommissioning Plan.

(b) The Management Committee shall attempt to agree upon the Decommissioning Plan within sixty (60) days following its receipt thereof, and the Management Committee may approve the proposed Decommissioning Plan in whole or in part. If an Impasse occurs with respect to the proposed Decommissioning Plan (or any part thereof), then the matter shall be resolved pursuant to the arbitration provisions set forth in Section 18.3.

(c) Owner shall use commercially reasonable efforts not to exceed the estimated amounts set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto); provided, however, that all Net Decommissioning Costs actually incurred by Owner, whether or not set forth in such Decommissioning Plan, shall be recoverable under this Agreement in accordance with this Section 9.3, subject to (i)

reallocation upon a Subsequent Use, if any, as described in Section 9.3.4, and (ii) challenge on prudence grounds, if applicable, as described in Section 9.3.6.

Section 9.3.3. Payment of Decommissioning Costs.

(a) Unless this Agreement is terminated prior to the expiration of the Term under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3 (in which case clause (c) below shall apply) or under Section 3.3.7 or Section 15.4 (in which case clause (d) below shall apply), Owner shall include the Levelized Monthly Decommissioning Payment in the Formula Rate during each of the last sixty (60) months of the Term (excluding any extension of the Term made after the thirty-fifth (35th) anniversary of the Commercial Operation Date pursuant to Section 9.1 or Section 16.4) (the "Decommissioning Payment Period"). If the Management Committee shall not have approved the Decommissioning Plan (or the Decommissioning Plan shall not have been determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto) prior to the commencement of the Decommissioning Payment Period, then the following provisions shall apply, notwithstanding anything herein to the contrary:

(i) The Levelized Monthly Decommissioning Payment included in the Formula Rate pursuant to this clause (a) shall be equal to (A) the estimated Net Decommissioning Costs, as set forth in the Decommissioning Plan delivered to the Management Committee under Section 9.3.2(a), multiplied by (B) the Decommissioning Payment Formula (each such monthly payment amount, the "Preliminary Monthly Decommissioning Payment").

(ii) Promptly after the Decommissioning Plan has been approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), but in no event later than thirty (30) days thereafter, Owner shall complete the following tasks: (A) calculate the Levelized Monthly Decommissioning Payment in accordance with Section 9.3.1(b); (B) retroactively adjust all payments previously made by Purchaser with respect to the Decommissioning Payment Period to reflect the Levelized Monthly Decommissioning Payment rather than the Preliminary Monthly Decommissioning Payment and (C) thereafter conform all future Invoices to reflect such Levelized Monthly Decommissioning Payments.

(iii) If and to the extent the aggregate Levelized Monthly Decommissioning Payments owed by Purchaser for the period prior to the date on which Owner shall have completed the tasks described in clause (a)(ii) above is less than the aggregate Preliminary Monthly Decommissioning Payments made by Purchaser for such period, then, within thirty (30) days after the calculation of the Levelized Monthly Decommissioning Payment contemplated by clause (a)(ii) above, Owner shall withdraw from the Decommissioning Fund and refund to Purchaser such overpayment in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. If and to the extent the aggregate Levelized Monthly Decommissioning Payments owed by Purchaser for the period prior to the date on which Owner shall have completed the tasks described in clause (a)(ii) above is greater than the aggregate Preliminary Monthly Decommissioning Payments made by Purchaser for such period, then, within thirty (30) days after a written demand therefor from Owner, Purchaser shall deposit into the Decommissioning

Fund such deficiency in immediately available funds in accordance with the terms and conditions established by the Management Committee, as contemplated by clause (b) below. Notwithstanding anything herein to the contrary, the withdrawal of any overpayment or the deposit of any deficiency, in each case, contemplated by this clause (a)(iii) shall not be subject to the provisions of Section 14.5.

(b) All Levelized Monthly Decommissioning Payments and Preliminary Monthly Decommissioning Payments, as applicable, included in the Formula Rate pursuant to clause (a) above and the Decommissioning Estimate described in clause (c) below, that are, in each case, paid by Purchaser shall be deposited into an external fund created on terms and conditions established by the Management Committee to protect the interests of each Party and to ensure that such fund is used for the purposes contemplated by this Agreement (the "Decommissioning Fund"), until applied to the Net Decommissioning Costs in accordance with Section 9.3.5(c) or refunded to Purchaser under Section 9.3.5(e).

(c) If this Agreement is terminated prior to the expiration of the Term under Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3, then Purchaser shall deposit into the Decommissioning Fund, an amount equal to (i) the estimated Net Decommissioning Costs, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto) (which estimated Net Decommissioning Costs, solely for the purpose of calculating the Decommissioning Estimate, shall be expressed in dollars as of the date on which this Agreement is terminated as if the Decommissioning were to commence as of such date), less (ii) the balance, if any, in the Decommissioning Fund as of the date such payment is due (the "Decommissioning Estimate"). Purchaser shall make such payment within thirty (30) days following the later to occur of (A) the receipt by Purchaser of the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto) and (B) the date on which the estimated Net Decommissioning Costs have been redetermined, as provided in the immediately ensuing sentence (the "Decommissioning Payment Date"). If this Agreement is terminated prior to the expiration of the Term pursuant to Section 3.3 (excluding Section 3.3.7 and Section 3.3.12) or Section 15.3, but after the Decommissioning Plan has been approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), then the Parties shall agree upon modifications to the estimated Net Decommissioning Costs, as set forth in such Decommissioning Plan, consistent with the first sentence of this clause (c). Any Dispute with respect to such redetermination shall be resolved pursuant to the arbitration provisions set forth in Section 18.3.

(d) If this Agreement is terminated prior to the expiration of the Term pursuant to Section 3.3.7 or Section 15.4, then Purchaser shall have no liability for any Decommissioning Costs, and Owner shall refund to Purchaser all amounts remaining in the Decommissioning Fund no later than sixty (60) days after such termination.

(e) If Hydro-Québec pays to Owner the Decommissioning Liquidated Damages, as provided in the Purchaser Guaranty, then such payment shall satisfy, in full, the obligations of Purchaser to pay Decommissioning Costs and Purchaser shall cease to have (i) any further obligation to pay any Decommissioning Costs hereunder, including under

Section 9.3.5(d), (ii) any right to any reimbursement, refund or reduction if the actual Net Decommissioning Costs are less than the Decommissioning Liquidated Damages, including under Section 9.3.5(e) and (iii) any right to challenge the prudency of the Net Decommissioning Costs or the Decommissioning Estimate under Section 9.3.6 or otherwise.

Section 9.3.4. Subsequent Use. In the event Owner (a) receives an offer for a Subsequent Use for service to commence immediately following the expiration or earlier termination of the Term or at any time thereafter until the Northern Pass Transmission Line has been fully Decommissioned and (b) desires to accept such offer or otherwise enter into another arrangement for a Subsequent Use, Owner shall notify Purchaser in writing of the material terms and conditions of such proposed Subsequent Use and Owner and Purchaser shall negotiate in good faith with such proposed third-party transmission customer or ISO-NE, as applicable, to determine the allocation of Net Decommissioning Costs between Purchaser and such proposed third-party transmission customer or ISO-NE, as applicable. Any Net Decommissioning Costs allocated to Purchaser shall be fixed by reference to the budgeted amounts for Net Decommissioning Costs, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), and shall not be subject to any payments or refunds pursuant to Section 9.3.5(d) or Section 9.3.5(e) with respect to Decommissioning Costs actually incurred by Owner or Salvage Proceeds actually received by Owner in connection with the Decommissioning of the Northern Pass Transmission Line. If the Parties and the proposed third-party transmission customer or ISO-NE, as applicable, fail to reach agreement on the allocation of Net Decommissioning Costs between Purchaser and such proposed third-party transmission customer or ISO-NE, as applicable, within sixty (60) days after the receipt by Purchaser of the notice described in the first sentence of this Section 9.3.4, then Owner shall make a unilateral filing under Section 205 of the Federal Power Act to establish such allocation of Net Decommissioning Costs, consistent with this Section 9.3.4, and Purchaser shall have the right to challenge such filing. If Owner enters into a contract or other arrangement for such Subsequent Use, then Owner shall deliver to Purchaser a statement setting forth in reasonable detail the amount equal to (i) the Net Decommissioning Costs, less (ii) the sum of (A) the reallocated portion of the Net Decommissioning Costs and (B) the balance, if any, in the Decommissioning Fund as of the date such statement is due (the "Purchaser's Decommissioning Balance"), within thirty (30) days after the later to occur of (1) the date on which this Agreement has expired or otherwise terminated, (2) the date on which Owner has entered into such contract or other arrangement for such Subsequent Use or (3) provided Owner has made a unilateral filing with FERC to establish the allocation of Net Decommissioning Costs, the date on which FERC has issued an order establishing the allocation of Net Decommissioning Costs. If and to the extent the Purchaser's Decommissioning Balance is less than zero (0), then, concurrently with the delivery of such statement, Owner shall refund to Purchaser the absolute value of the Purchaser's Decommissioning Balance, in a single lump sum and in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing. If and to the extent the Purchaser's Decommissioning Balance is greater than zero (0), then Purchaser shall pay the Purchaser's Decommissioning Balance to Owner, in a single lump sum due thirty (30) days following the receipt by Purchaser of such statement, but otherwise in a manner consistent with Section 14.1. Either Party may deduct and setoff payment of such Purchaser's Decommissioning Balance against any accrued but unpaid payment obligation of the other Party to such Party hereunder.

Section 9.3.5. Decommissioning Process. The following provisions shall apply to the Decommissioning of the Northern Pass Transmission Line unless a Subsequent Use has occurred:

(a) Owner shall complete the Decommissioning of the Northern Pass Transmission Line in accordance with the Decommissioning Plan, unless otherwise required by Applicable Law.

(b) In connection with the Decommissioning of the Northern Pass Transmission Line, Owner shall (i) use commercially reasonable efforts to sell the Project Assets (other than the Project Assets acquired by Purchaser pursuant to Section 3.5(a)(iii)) at their fair market value to one or more third parties (which may include Affiliates of Owner) and (ii) credit the proceeds of such sale, net of reasonable fees (including attorneys' fees) and other expenses (including storage costs) incurred by Owner in connection with such sale (the "Salvage Proceeds") against the Decommissioning Costs, and to the extent the Salvage Proceeds exceed the Decommissioning Costs, against other amounts owed to Owner by Purchaser under this Agreement. For the avoidance of doubt, no Project Asset acquired by Purchaser pursuant to Section 3.5(a)(iii) shall generate any Salvage Proceeds.

(c) Owner shall draw upon the Decommissioning Fund on a monthly basis for its actual Net Decommissioning Costs. The Decommissioning Fund shall be administered in all other respects consistent with the terms and conditions established by the Management Committee for the Decommissioning Fund.

(d) In the event Owner's draws upon the Decommissioning Fund for its actual Net Decommissioning Costs shall have exhausted the Decommissioning Fund prior to the completion of Decommissioning, Owner shall thereafter invoice Purchaser on a monthly basis (unless another interval shall have been agreed by the Parties or approved by the Management Committee) for Owner's actual Net Decommissioning Costs thereafter incurred until the Decommissioning has been completed. Owner shall submit such invoices to Purchaser (in reasonable detail to evidence the basis for individual billings and charges), and Purchaser shall pay the amounts set forth in such invoices, in each case, in a manner consistent with Section 14.1 (unless another manner shall have been agreed by the Parties or approved by the Management Committee). Purchaser's payment of any amounts set forth in such invoices (i) shall not be deemed to be an acceptance or approval by Purchaser of the correctness or prudency of the costs reflected therein (provided that nothing herein shall alter the otherwise applicable burden of proof set forth in Section 8.1.4 for prudency challenges or time limit set forth in Section 14.3(b), as modified by Section 9.3.6, within which Purchaser has the right to challenge an invoice) and (ii) shall be without prejudice to any right or remedy that Purchaser may have under this Agreement, including under Section 9.3.6, to contest any such amount. Purchaser may deduct and setoff payment of such amounts against any accrued but unpaid payment obligations of Owner to Purchaser hereunder.

(e) If and to the extent Owner's draws upon the Decommissioning Fund shall not have exhausted the Decommissioning Fund upon the completion of Decommissioning, then, within thirty (30) days following the completion of the Decommissioning, Owner shall refund to Purchaser, in a single lump sum and in immediately

available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing, the remaining balance in the Decommissioning Fund as of the date such payment is due. Owner may deduct and setoff payment of such refund against any accrued but unpaid payment obligations of Purchaser to Owner hereunder.

Section 9.3.6. Prudency Challenges. Unless a Subsequent Use has occurred and subject to Section 9.3.3(e), Decommissioning Costs actually incurred by Owner and invoiced to Purchaser as provided in this Section 9.3, and Salvage Proceeds actually received by Owner and credited against the Decommissioning Costs or against other amounts owed to Owner by Purchaser under this Agreement, as provided in this Section 9.3, are subject to Purchaser's right to challenge the prudency of such Decommissioning Costs or Salvage Proceeds before FERC to the extent such Decommissioning Costs are higher than, or such Salvage Proceeds are lower than, the budgeted amounts therefor, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions herein in the event of an Impasse with respect thereto), which prudency challenge shall be subject, *mutatis mutandis*, to the procedures and standards set forth in Section 8.1.4. For purposes of applying the provisions of Section 14.3 to such prudency challenges, all invoices rendered pursuant to Section 9.3.5(d) shall be deemed to have been rendered on the date the last such invoice shall have been rendered.

Section 9.3.7. Limitations on the Parties' Decommissioning Rights and Obligations. The following provisions shall apply, notwithstanding anything herein to the contrary:

(a) Subject to Section 3.5(a)(iii), following termination of this Agreement pursuant to Section 3.3.2, the Parties shall have no rights or obligations under this Section 9.3 or any other provision in this Agreement with respect to the Decommissioning of the Northern Pass Transmission Line.

(b) If Owner shall have failed to comply with the provisions of Section 5.1.2(a)(ii)(A), then, subject to Section 3.5(a)(iii), following termination of this Agreement pursuant to Section 3.3.3, the Parties shall have no rights or obligations under this Section 9.3 or any other provision in this Agreement with respect to the Decommissioning of the Northern Pass Transmission Line.

(c) If Owner shall have failed to comply with the provisions of Section 5.1.2(a)(ii), then, subject to Section 3.5(a)(iii), following termination of this Agreement pursuant to Section 3.3.5(a), the Parties shall have no rights or obligations under this Section 9.3 or any other provision in this Agreement with respect to the Decommissioning of the Northern Pass Transmission Line.

ARTICLE 10

RESALE OF TRANSMISSION SERVICE

Section 10.1. Resale Rights of Purchaser. If and to the extent Purchaser determines from time to time, and in its sole discretion, that the transmission capacity available

over the Northern Pass Transmission Line exceeds Purchaser's needs, Purchaser shall then offer to resell such unused capacity to third parties in accordance with Applicable Law as may then be in effect (including the terms and conditions of FERC Order No. 890 *et seq.*, if applicable).

Section 10.2. Capacity Releases for Daily and Hourly Use. From and after the Commercial Operation Date, if and to the extent the Total Transfer Capability of the Northern Pass Transmission Line exceeds the amount of electrical energy that Purchaser has scheduled for delivery over the Northern Pass Transmission Line by the applicable scheduling deadline (as in effect at such time) established pursuant to the Scheduling Rules, then the transmission capacity that is available for resale to third parties for the following day, and the price at which any such resales are offered, shall be posted on the OASIS site established pursuant to Section 10.3.

Section 10.3. OASIS.

(a) The Parties shall jointly contract with an independent, non-affiliated third party (the "OASIS Provider") for use of an OASIS site. The OASIS Provider shall post the transmission capacity available for resale over the Northern Pass Transmission Line and schedule related transmission service over the Northern Pass Transmission Line on such OASIS site in accordance with written instructions that Purchaser or the OASIS Administrator, as applicable, may provide to the OASIS Provider from time to time. In connection with any such posting, the Parties shall comply with FERC Order No. 890 *et seq.* at all times and shall direct the OASIS Provider to comply with same.

(b) To the extent resales are made available by Purchaser pursuant to Section 10.1, the OASIS Provider shall post on the OASIS site information regarding such resales, (i) in accordance with written instructions provided by Purchaser from time to time and (ii) at a price established by Purchaser from time to time, and in its sole discretion, as permitted under Applicable Law.

(c) The Parties shall jointly contract with an independent, non-affiliated third party (the "OASIS Administrator"), which entity may be the same as or different from the OASIS Provider, to carry out the capacity release functions for daily and hourly resales set forth in Section 10.2 in a commercially reasonable manner and in compliance with applicable FERC rules and regulations.

(i) In addition to assigning the responsibility for such capacity release functions, such contract shall also contain the following provisions, at a minimum, unless waived by the Management Committee, (A) to the extent neither Party voluntarily assumes the responsibility to perform Necessary Administrative Functions, the OASIS Administrator shall be required to perform such functions, (B) the OASIS Administrator shall be required to use commercially reasonable efforts to collect amounts due but not paid by any third party in connection with any capacity releases and transmission resales made pursuant to this Article 10 and (C) the Parties shall have the right to terminate the contract, with or without cause, within a reasonable timeframe and without damages. The term "Necessary Administrative Functions" as used herein includes the following functions: entering into transmission service agreements with third-party assignees; billing and collecting transmission service payments from third-party assignees; crediting the proceeds of any capacity releases and

transmission resales to Purchaser; making all required regulatory filings (such as Electronic Quarterly Reports) with FERC; and performing any other administrative functions relating to capacity releases, transmission resales or the scheduling of transmission service. Any Dispute with respect to the selection of an OASIS Administrator or the terms and conditions of a contract to employ an OASIS Administrator shall be resolved pursuant to the arbitration provisions set forth in Section 18.3, but any such resolution shall be consistent with the terms of this clause (c)(i). Following resolution of any such Dispute, the Parties will take such actions as are reasonably necessary to contract with the OASIS Administrator on the terms and conditions consistent with the resolution of such Dispute.

(ii) Each Party shall designate a representative, and the two representatives so designated shall jointly be assigned the responsibility to (A) monitor the OASIS Administrator's activities, (B) administer the contract entered into by the Parties with the OASIS Administrator, and (C) provide periodic reports to the Management Committee, as requested by any Manager, with respect to the performance of the OASIS Administrator.

(iii) The costs incurred pursuant to the contract with the OASIS Administrator shall be recovered under the Formula Rate in accordance with Article 8; provided that Purchaser shall not have the right under Section 8.1.4 to challenge costs incurred by Owner under a contract with the OASIS Administrator to which Purchaser is a party. Further, Purchaser shall not have the right under Section 8.1.4 to challenge the prudency of revenues received from resales or reassignments of transmission capacity to third parties made by the OASIS Administrator pursuant to clause (c)(i) above and credited to Purchaser under the Formula Rate in accordance with Article 8.

(iv) If either Party believes that the OASIS Administrator is acting in a manner adverse to its interests, such Party shall then have the right to submit the matter to the Management Committee for resolution. Any Impasse with respect to such matter shall be resolved pursuant to the arbitration provisions set forth in Section 18.3. Following resolution of any such Dispute, the Parties will take such actions as are reasonably necessary to implement the resolution of such Dispute.

(v) Nothing contained herein shall be construed as preventing a Party from enforcing the terms and conditions of any contract with an OASIS Administrator, including the recovery of damages against the OASIS Administrator for breach, non-performance, negligence or other misfeasance in performing the Necessary Administrative Functions or its other duties thereunder; provided, however, that damages received from the OASIS Administrator by Owner, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with the receipt and final collection of such amounts, shall be credited to the Formula Rate pursuant to Article 8 to the extent such damages relate to costs paid or payable by Purchaser under the Formula Rate or revenue credits for the services of the OASIS Administrator.

Section 10.4. Proceeds from Capacity Releases and Transmission Resales. Except as otherwise provided in Section 15.3(b), the proceeds received by Owner of any capacity releases and transmission resales made pursuant to this Article 10 shall be credited, net of reasonable fees (including attorneys' fees) and other expenses incurred in connection with

performance of the functions described in Section 10.2 and Section 10.3, against any Transmission Service Payment or other amounts owed to Owner by Purchaser for the calendar month subsequent to the calendar month in which such proceeds were received. Owner shall have no liability for, or obligation to credit to Purchaser under the Formula Rate, amounts due but not paid by any third party in connection with any capacity releases and transmission resales made pursuant to this Article 10.

Section 10.5. Owner's Rights and Obligations. Except as expressly provided in this Agreement, Owner shall have no right or obligation to offer any transmission service over the Northern Pass Transmission Line for sale or resale to any Person other than Purchaser.

ARTICLE 11

REAL POWER LOSSES, CONGESTION AND CAPACITY RIGHTS

Section 11.1. Real Power Losses. Purchaser shall be responsible for all Real Power Losses associated with Firm Transmission Service and Additional Transmission Service between the U.S. Border and the Delivery Point; provided, however, that, if and to the extent any Real Power Losses associated with Firm Transmission Service and Additional Transmission Service between the U.S. Border and the Delivery Point are due to Owner's failure to exercise Good Utility Practice or otherwise discharge its obligations under this Agreement, such incremental Real Power Losses shall be treated as Non-Excused Outages for which Owner shall be liable in accordance with Section 7.4, and the rights and remedies contemplated by Section 7.4, including the rights provided in Section 3.3.12, shall collectively be the sole and exclusive remedy of Purchaser with respect to any such incremental Real Power Losses as provided in Section 7.4.4. The assignment of losses associated with the transmission of electric power over the AC Upgrades shall be determined in accordance with the ISO-NE Rules.

Section 11.2. Other Rights.

(a) Purchaser shall be entitled to the following, without duplication and without additional cost to Purchaser or compensation to Owner, (i) all Other Transmission Rights associated with the Northern Pass Transmission Line or, to the extent the costs of which are incurred by Owner and recovered from Purchaser under this Agreement, the AC Upgrades, in each case, that are issued in accordance with the ISO-NE Tariff or otherwise granted under the ISO-NE Rules, or otherwise created or awarded by ISO-NE, and (ii) all other Market Products that are issued in accordance with the ISO-NE Tariff or granted under the ISO-NE Rules, or otherwise created or awarded by ISO-NE, that derive from the acquisition of transmission service over the Northern Pass Transmission Line. As Owner's sole obligation under this clause (a), upon its receipt of any of the entitlements or rights described in the foregoing sentence, Owner shall promptly convey such entitlements or rights to Purchaser.

(b) In the event tie benefits or interconnection capability credits (or any similar concept) are ever deemed applicable to the Northern Pass Transmission Line and to the extent allocated to either Party, Purchaser shall be entitled to one hundred

percent (100%) of the economic benefits associated therewith (however entitled and whether existing now or in the future), without additional cost to Purchaser or compensation to Owner.

(c) Owner shall have no obligation to support the creation or establishment of any of the rights described in clauses (a)(ii) and (b) above, but Owner may not oppose the creation or establishment of any such right, unless otherwise agreed in writing by Purchaser. Neither Section 2.4 nor the foregoing sentence shall be construed in any way to limit the right of any Affiliate of Owner to oppose the creation or establishment of any of the rights described in clauses (a)(ii) and (b) above.

ARTICLE 12

ANCILLARY SERVICES

Section 12.1. Responsibility for Ancillary Services. Purchaser shall be responsible for any Ancillary Services that are required under the ISO-NE Tariff in connection with the transmission of electric power over the Northern Pass Transmission Line. Responsibility for ancillary services that are required under the ISO-NE Tariff in connection with the transmission of electric power over the AC Upgrades shall be determined in accordance with the ISO-NE Rules.

Section 12.2. Revenues from Ancillary Services. All revenues received by Owner in respect of any ancillary services (however defined) associated with the Northern Pass Transmission Line (other than revenues received in respect of ancillary services associated with transmission service scheduled for a third-party customer) and, to the extent applicable, the AC Upgrades shall be credited, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner with respect to the provision of such ancillary services, against any amounts owed to Owner by Purchaser for the calendar month subsequent to the calendar month in which such revenues were received by Owner.

ARTICLE 13

MANAGEMENT COMMITTEE

Section 13.1. Management Committee. No later than ten (10) days after the Execution Date, the Parties shall establish a committee ("Management Committee") by appointment of the Managers, which committee shall (a) coordinate and oversee the implementation and administration of this Agreement, including matters relating to the Parties' performance obligations under this Agreement, but excluding decisions that may be made by either or both of the Parties under the express terms and conditions of this Agreement, (b) bear responsibility for the matters expressly under the purview of the Management Committee pursuant to the terms and conditions of this Agreement, and (c) handle any other matters delegated to the Management Committee by the express written agreement of the Parties. The ensuing provisions of this Article 13 shall apply to the Management Committee.

Section 13.2. Appointment and Authority of Managers.

(a) Owner and Purchaser shall each be entitled to appoint one member to serve on the Management Committee as a voting member (each a "Manager"). In addition, Owner and Purchaser shall each designate, within ten (10) days after the Execution Date, an alternate to its Manager (each, an "Alternate Manager") with the authority to serve in place of, and with the authority of, such Manager solely if such Manager is absent from, or unavailable to attend, a Management Committee meeting. Owner and Purchaser may also each appoint such other non-voting members of the Management Committee as such Party deems advisable to perform the tasks assigned to the Management Committee, and may remove or replace such non-voting members, in each case, in its sole discretion. Each Party shall promptly give written notice to the other Party of any change in the business address or business telephone of its Manager or Alternate Manager (collectively, its "Authorized Representatives").

(b) Each Authorized Representative shall be an agent of the Party that designated such Authorized Representative, and subject to Section 13.1 and the next two sentences, each Authorized Representative shall have the right and authority to bind the Party such Authorized Representative represents. In respect of the Authorized Representatives, (i) each Authorized Representative shall have power to act (or refrain from acting) solely in accordance with the wishes of the Party that designated such Authorized Representative, (ii) the acts of an Authorized Representative with respect to any matter shall be deemed to be the acts of the Party that designated such Authorized Representative, and (iii) no Authorized Representative shall owe (or be deemed to owe) any duty (fiduciary or otherwise) to any Party other than the Party that designated such Authorized Representative. Notwithstanding the foregoing, no Authorized Representative, in such capacity, shall have the authority to (A) amend, waive, revise, modify or terminate this Agreement or any portion thereof, (B) serve any notice alleging breach of this Agreement, or (C) enter into, settle or otherwise dismiss any FERC or arbitration proceeding under Section 18.2 or Section 18.3.

(c) The compensation and expenses of Owner's Authorized Representatives, including an allocated share of overhead, shall be recoverable under the Formula Rate in accordance with Article 8.

Section 13.3. Term of Managers; Resignation, Removal and Vacancies. Each Authorized Representative shall serve until the earlier to occur of such Authorized Representative's resignation or removal. An Authorized Representative may resign as such at any time by delivering written notice to that effect to Owner and Purchaser, and the effective date of such resignation shall be the date upon which such notice is delivered, unless another date therefor is specified therein. An Authorized Representative may be removed or replaced at any time and for any reason and without the approval of the other Party by the Party that appointed such Authorized Representative. In the event a vacancy on the Management Committee occurs as a result of the death, disability, resignation, removal or otherwise of a Manager, such vacancy shall be promptly filled by the Party that appointed the vacating Manager. Such Party shall provide written notice to the other Party whenever an Authorized Representative appointed by such Party is removed or replaced.

Section 13.4. Meetings; Attendance.

(a) Meetings of the Management Committee shall be held on a monthly basis prior to the Commercial Operation Date and quarterly thereafter, or more frequently as determined by the Parties or the Management Committee, on such dates and at such times as may be determined by the Management Committee. Notwithstanding the foregoing sentence, a Party may call a special meeting by reasonable advance notice to the other Party's Manager in writing.

(b) Each Party shall use reasonable efforts to cause its Manager or Alternate Manager to attend each Management Committee meeting, and no Party shall withhold the presence or participation of its Manager or Alternate Manager to prevent, delay or forestall decisions on matters under consideration by the Management Committee. The Parties shall cause their respective Authorized Representatives not to delay unreasonably any actions of the Management Committee.

(c) All meetings of the Management Committee shall be held at Owner's principal place of business or at such other place (or means if by telephone conference or other means) as shall be agreed upon by the Parties or the Management Committee. A designee of the Management Committee shall provide written notice to each Party and Manager stating the date and hour of each Management Committee meeting, together with a detailed agenda for the meeting, not less than five (5) Business Days before such meeting. Attendance of an Authorized Representative of a Party at a Management Committee meeting shall constitute a waiver of the foregoing notification requirement by such Party.

(d) A designee of the Management Committee shall record minutes of each meeting and, within seven (7) Business Days following such meeting, shall provide to each Party and Manager a copy of such minutes. If applicable, such minutes shall be in such detail as required for purposes of Section 6.7.

Section 13.5. Rules. The Management Committee may adopt such rules of order as it considers necessary or appropriate for the conduct of its business and the exercise of its powers, none of which shall conflict with this Agreement.

Section 13.6. Action by the Management Committee. An Authorized Representative of Owner and an Authorized Representative of Purchaser shall together constitute a quorum for the transaction of business, and each Authorized Representative shall have one (1) vote on all decisions of the Management Committee. The affirmative vote of an Authorized Representative of Owner and an Authorized Representative of Purchaser shall be the act of the Management Committee.

Section 13.7. Action by Written Consent. Any action that may be taken by the Management Committee under this Agreement may be taken without a meeting and without a vote if there is written consent, setting forth the action so taken, and signed by an Authorized Representative of Owner and an Authorized Representative of Purchaser or with the electronic approval of an Authorized Representative of Owner and an Authorized Representative of Purchaser. Any action taken by the written consent shall have the same force and effect as if

taken at a meeting. If applicable, such written consent shall be in such detail as required for purposes of Section 6.7.

Section 13.8. Telephonic Meetings. Managers may participate in any meeting of the Management Committee by means of conference telephone or similar communication equipment by which both Managers participating in the meeting can hear each other at the same time. Such participation shall constitute presence in person at the meeting.

Section 13.9. Impasse between the Managers. Except in the case of any Annual Plan and Operating Budget, an "Impasse" shall be deemed to have occurred if, for any reason, the Authorized Representatives are unable to reach agreement on a matter submitted to the Management Committee for approval or any Dispute referred to the Management Committee for resolution within thirty (30) days after such submission or referral, or such earlier or longer period as the Management Committee may establish. In the case of any Annual Plan and Operating Budget, an "Impasse" shall be deemed to have occurred if, for any reason, the Authorized Representatives are unable to reach agreement on an Annual Plan and Operating Budget submitted to the Management Committee within sixty (60) days after such submission, or such earlier or longer period as the Management Committee may establish.

ARTICLE 14

BILLING AND PAYMENTS

Section 14.1. Invoices.

(a) No later than sixty (60) days before the date Owner reasonably expects the Commercial Operation Date to occur, Owner shall deliver to Purchaser an estimated Revenue Requirement for the first Contract Year, pursuant to which the Transmission Service Payments shall be calculated under the Formula Rate, such estimated Revenue Requirement to be effective as of the Commercial Operation Date.

(b) The monthly Transmission Service Payments shall be calculated as follows:

(i) The monthly Transmission Service Payments for the first Contract Year shall be calculated by dividing (A) the estimated Revenue Requirement described in clause (a) above, by (B) the number of calendar months in such Contract Year.

(ii) The monthly Transmission Service Payments for any Contract Year thereafter, other than the final Contract Year, shall be calculated by dividing (A) the estimated Revenue Requirement for such Contract Year by (B) twelve (12).

(iii) The monthly Transmission Service Payments for the final Contract Year shall be calculated by dividing (A) the estimated Revenue Requirement for such final Contract Year by (B) number of calendar months in such Contract Year.

(c) Within seven (7) Business Days after the first day of each calendar month following the commencement of the Operation Phase, Owner shall submit an Invoice to Purchaser for the Transmission Service Payments owed for the preceding calendar month, and Purchaser shall pay the amounts set forth in the Invoice within fourteen (14) Business Days following its receipt of such Invoice. During the Decommissioning Payment Period, all Invoices shall separately set forth the portion of the Transmission Service Payment that is associated with the Levelized Monthly Decommissioning Payment or Preliminary Monthly Decommissioning Payment, as applicable. All payments shall be made in immediately available funds payable to Owner by wire transfer to a bank named by Owner, in accordance with wiring instructions provided to Purchaser by Owner in writing, except that the Levelized Monthly Decommissioning Payment or Preliminary Monthly Decommissioning Payment, as applicable, shall be made in immediately available funds and deposited into the Decommissioning Fund in accordance with the terms and conditions established by the Management Committee, as contemplated by Section 9.3.3(b). Owner shall be entitled to change the place or recipient for payment by thirty (30) days' prior written notice to Purchaser.

(d) Invoices provided under this Agreement will be based upon the estimated Revenue Requirement, subject to a true-up to actual costs pursuant to Section 14.2. For the first Contract Year, the estimated Revenue Requirement described in clause (a) above shall become effective as of the Commercial Operation Date. For each Contract Year thereafter, the estimated Revenue Requirement for such Contract Year, shall become effective on January 1st of such Contract Year.

Section 14.2. Reconciliation; Audit Rights.

(a) Owner shall provide Purchaser with a statement setting forth in reasonable detail all of the costs and expenses used to calculate the trued-up annual Revenue Requirement pursuant to the Formula Rate during the prior year, and the activities associated therewith, no later than sixty (60) days after Owner has filed its FERC Form 1 for such prior year. The foregoing statement shall detail all components of the amounts included in the Formula Rate and all calculations used to determine the final Transmission Service Payments thereunder (based upon costs actually incurred).

(b) At Purchaser's reasonable request, Owner shall make available to Purchaser any information reasonably necessary to permit Purchaser to audit Owner's application of the Formula Rate. At Purchaser's reasonable request, Owner shall also make available to Purchaser any information reasonably necessary to support the borrowing cost of any Additional Financing described in clause (a)(i) of the definition thereof. Owner acknowledges and agrees that the making of any payment hereunder by Purchaser or the approval of any cost estimate, budget, schedule or maintenance plan by the Management Committee shall be without prejudice to the audit rights of Purchaser provided herein.

(c) If and to the extent the total amount of the estimated Transmission Service Payments initially paid by Purchaser for any calendar year is greater than the costs actually incurred in such calendar year under the Formula Rate, then Owner shall refund to Purchaser the excess amounts collected, together with interest thereon calculated pursuant to Section 14.5(a), in a single lump sum due on the same date on which Owner is

required to submit the first Invoice to be delivered after the receipt by Purchaser of the statement described in clause (a) above. If and to the extent the total amount of the estimated Transmission Service Payments initially paid by Purchaser for any calendar year is less than the costs actually incurred during such calendar year under the Formula Rate, then Purchaser shall pay a surcharge to Owner in the amount of such deficiency, together with interest thereon calculated pursuant to Section 14.5(b), which surcharge shall be payable in a single lump sum due on the same date on which Purchaser is required to pay the amounts set forth in the first Invoice to be delivered after the receipt by Purchaser of the statement described in clause (a) above. Solely for purposes of performing the calculations set forth in this clause (c), for any calendar year, the actual amounts associated with the Levelized Monthly Decommissioning Payments or Preliminary Monthly Decommissioning Payments, as applicable, during such calendar year shall be deemed to be equal to the estimated amounts associated with the Levelized Monthly Decommissioning Payments or Preliminary Monthly Decommissioning Payments, as applicable, that are included in the estimated Transmission Service Payments for such calendar year.

Section 14.3. Procedures for Billing Disputes.

(a) In the event of any Impasse or other Dispute with respect to the amount owed to Owner by Purchaser under this Agreement, Purchaser shall have no right to withhold payment of the Disputed amount pending resolution of the Dispute; provided, however, that, in the event such Dispute is resolved in favor of Purchaser, Owner shall complete the following tasks consistent with the resolution of such Dispute: (i) retroactively adjust all payments previously made by Purchaser; (ii) promptly refund all overpayments previously made by Purchaser, together with interest thereon in accordance with Section 14.2(c), in immediately available funds or by wire transfer, in each case, in accordance with wiring instructions provided to Owner by Purchaser in writing; and (iii) thereafter conform all future Invoices to reflect the resolution of such Dispute. Purchaser's payment of any Disputed amounts (A) shall not be deemed to be an acceptance or approval by Purchaser of the correctness or prudency of the costs reflected therein (provided that nothing herein shall alter the otherwise applicable burden of proof set forth in Section 8.1.4 for prudency challenges or time limit set forth in clause (b) below within which Purchaser has the right to challenge an Invoice) and (B) shall be without prejudice to any right or remedy that Purchaser may have under this Agreement, including under Section 8.1.4, to contest any such amount.

(b) Purchaser shall not have the right to challenge any Invoice or to bring any action of any kind challenging the propriety of any Invoice after the second (2nd) anniversary of the date payment of the Invoice was due; provided, however, that, in the case of an Invoice based upon cost estimates, such two (2)-year period shall be based upon the date such Invoice is reconciled to actual costs in a statement provided to Purchaser unless the challenge equally applied to such cost estimates, in which case such two (2)-year period shall be based upon the date on which such cost estimates was provided to Purchaser. If an Invoice is not rendered within two (2) years after the end of the calendar month during which such Invoice should have been rendered hereunder, then the right to payment of such Invoice is waived.

Section 14.4. Reporting of Revenue Credits. In the event Owner becomes aware of a material change in the revenue credits to be made to Purchaser in any calendar month as compared with the revenue credits contained in the applicable Annual Plan and Operating Budget, Owner shall promptly notify the Management Committee of the nature and amount of such revenue credits.

Section 14.5. Interest. All interest payable under this Section 14.5 shall be calculated pursuant to 18 C.F.R. § 35.19a(a), as such regulation (or any successor thereto) is in effect during the period during which such interest is due.

(a) Interest on refunds owed to Purchaser by Owner under Section 3.4(b), Section 9.2 or Section 14.2(c) shall begin to accrue on the amount subject to refund, as originally invoiced, from the earlier to occur of the due date or the date of payment of the monthly Invoices to which the refund relates and shall continue to accrue until the date of payment of such refund.

(b) Interest on surcharges owed to Owner by Purchaser under Section 3.4(b) or Section 14.2(c) shall begin to accrue on the surcharge from the due date of the monthly Invoices to which the surcharge relates and shall continue to accrue until the date of payment of such surcharge.

(c) Amounts not paid when due to either Owner or Purchaser under this Agreement (other than amounts owed pursuant to Section 3.4(b), Section 9.2 or Section 14.2(c)) shall bear interest from the date such amount was due until the date of payment of such overdue amount. For the avoidance of doubt, as illustrated in Attachment I, if all or a portion of the amount to which such interest relates is later refunded pursuant to this Agreement, then, in calculating that refund, such interest shall not be included in the refund. Refunds of overpayments owed to Purchaser by Owner under this Agreement (other than amounts owed pursuant to Section 3.4(b), Section 9.2 or Section 14.2(c)) shall begin to accrue interest on the amount subject to refund, as originally invoiced, from the earlier to occur of the due date or the date of payment of the monthly Invoices to which the overpayment relates and shall continue to accrue interest until the date of payment of such refund.

Section 14.6. Obligation to Make Payments. The Parties acknowledge and agree that, except as set forth in Section 4.3.1, Section 7.4.1, Section 8.1.4, Section 14.7, Section 15.4(h) and Section 16.4, no cause or event whatsoever shall excuse or suspend Purchaser's obligation to pay Transmission Service Payments, Owner's estimate of the amounts owed to Owner by Purchaser under Section 3.3, the Decommissioning Estimate, or any other amounts payable by Purchaser under this Agreement. The Parties also acknowledge and agree that no cause or event whatsoever shall excuse or suspend any amounts payable by Owner under this Agreement.

Section 14.7. Offsets. Except as otherwise provided in Section 3.4(b), Section 9.3.4, Section 9.3.5(d), Section 9.3.5(e) and Section 15.4(h), neither of the Parties shall be entitled to deduct and setoff payment of any amount owed to such Party under this Agreement against payment of any amount owing under this Agreement or any other agreement between the Parties or their Affiliates.

ARTICLE 15

EVENTS OF DEFAULT AND REMEDIES

Section 15.1. Purchaser Defaults. Except to the extent excused as a result of an event of Force Majeure in accordance with Article 16, the occurrence of one or more of the following events shall constitute a default by Purchaser under this Agreement (a "Purchaser Default"):

(a) Purchaser's failure to pay any amount due to Owner under this Agreement by the due date, which failure is not cured within thirty (30) days after the receipt by Purchaser of a demand from Owner that such amount is due and owing and has not been timely paid.

(b) Purchaser's failure to comply in any material respect with the provisions of Article 17.

(c) Purchaser's failure to perform or comply with any of its obligations under this Agreement, other than those described in clauses (a) and (b) above, or under the Letter Agreement, in each case, in any material respect, and, if such failure is susceptible to cure, such failure continues for thirty (30) days after the receipt by Purchaser of written notice thereof from Owner, unless such cure shall reasonably require a longer period, in which case Purchaser shall be provided such additional period as necessary to complete such cure so long as Purchaser has promptly commenced such cure and thereafter diligently pursues and completes such cure.

(d) Any representation or warranty made by Purchaser in this Agreement is false or misleading at the time made and such inaccuracy has a material adverse effect on the ability of Owner to perform its obligations under this Agreement, individually or in the aggregate, or on the business, operations or financial condition of Owner.

(e) Any Insolvency Event occurs with respect to Purchaser.

Section 15.2. Owner Defaults. Except to the extent excused as a result of an event of Force Majeure in accordance with Article 16, the occurrence of one or more of the following events shall constitute a default by Owner under this Agreement (an "Owner Default"):

(a) Owner's failure to pay any amount due to Purchaser under this Agreement by the due date, which failure is not cured within thirty (30) days after the receipt by Owner of a demand from Purchaser that such amount is due and owing and has not been timely paid.

(b) An Owner Delay occurs and the Operation Phase has not commenced by the fifth (5th) anniversary of Owner's Initial Deadline (which fifth (5th) anniversary shall not be subject to extension for any event of Force Majeure).

(c) Owner's failure to comply with the provisions of Section 5.1.2(a)(ii).

(d) Owner's failure to comply with the provisions of Section 5.1.2(a)(iii).

(e) Owner's failure to comply with the provisions of Section 5.1.2(e).

(f) Owner's failure to comply with the provisions of Section 5.6; provided that such failure also constitutes a default under any Loan Agreement (or any agreement entered into by Owner with a Financing Party or any equity commitment or similar agreement entered into by any Affiliate of Owner with a Financing Party in connection therewith).

(g) Owner's failure to comply with the provisions of Section 5.7(a).

(h) A Non-Excused Outage occurs.

(i) Owner's failure to comply in any material respect with the provisions of Article 17.

(j) Owner's failure to perform or comply with any of its obligations under this Agreement, other than those described in clauses (a), (b), (c), (d), (e), (f), (g), (h) and (i) above, or under the Letter Agreement, in each case, in any material respect, and, if such failure is susceptible to cure, such failure continues for thirty (30) days after the receipt by Owner of written notice thereof from Purchaser, unless such cure shall reasonably require a longer period, in which case Owner shall be provided such additional period as necessary to complete such cure so long as Owner has promptly commenced such cure and thereafter diligently pursues and completes such cure.

(k) Any representation or warranty made by Owner in this Agreement is false or misleading at the time made and such inaccuracy has a material adverse effect on the ability of Purchaser to perform its obligations under this Agreement, individually or in the aggregate, or on the business, operations or financial condition of Purchaser.

(l) Any Insolvency Event occurs with respect to Owner.

Section 15.3. Remedies Upon Purchaser Default. Upon the occurrence of a Purchaser Default and at any time thereafter so long as the same is continuing, Owner shall be entitled, to the extent permitted by Applicable Law, to exercise one or more of the following remedies, as Owner shall elect:

(a) In the case of a Purchaser Default pursuant to Section 15.1(a), and subject to Section 5.8, Owner may terminate this Agreement by written notice to Purchaser as of a date that is not less than ninety (90) days after the date of such notice.

(b) In the case of a Purchaser Default pursuant to Section 15.1(a), and subject to Section 5.8, Owner may suspend all or part of Owner's obligations or Purchaser's rights under this Agreement during the period during which such Purchaser Default

is continuing. During any such period of suspension occurring after the Commercial Operation Date, (i) Purchaser shall not be entitled to schedule, and shall not schedule, any transactions over the Northern Pass Transmission Line and (ii) the OASIS Provider shall be directed to post any portion of the transmission capacity available over the Northern Pass Transmission Line and to attempt to sell such capacity to one or more third parties consistent with Article 10. The proceeds of any capacity releases and transmission resales made pursuant to the foregoing sentence and received by Owner, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with this Section 15.3(b), shall be credited against any accrued but unpaid payment obligation of Purchaser to Owner hereunder. Any proceeds in excess of such accrued but unpaid payment obligation of Purchaser shall be credited in accordance with Section 10.4; provided, however, that Owner shall have no liability for, or obligation to credit against any accrued but unpaid payment obligation of Purchaser to Owner hereunder, amounts due but not paid by any third party in connection with any capacity releases and transmission resales made pursuant to this Section 15.3(b).

(c) Subject to Article 19 and this Section 15.3, as applicable, Owner may recover all damages suffered by Owner that are due to a Purchaser Default, including, for the avoidance of doubt, any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Owner to recover any amounts owed to Owner by Purchaser under this Agreement.

(d) Owner may exercise and enforce any and all of its rights and remedies under the Purchaser Guaranty or any other financial assurances held by Owner.

(e) Owner may exercise any and all other rights and remedies that may be available to Owner at law or in equity, unless expressly prohibited or otherwise restricted by Article 19 or any other provision of this Agreement. Notwithstanding the foregoing sentence, Owner shall have no right to (i) terminate this Agreement based upon a Purchaser Default, except as provided in clause (a) above, or (ii) suspend transmission service under this Agreement based upon a Purchaser Default, except as provided in clause (b) above.

Section 15.4. Remedies Upon Owner Default. Upon the occurrence of an Owner Default and at any time thereafter so long as the same is continuing, Purchaser shall be entitled, to the extent permitted by Applicable Law, to exercise one or more of the following remedies, as Purchaser shall elect:

(a) In the case of an Owner Default pursuant to Section 15.2(b) or Section 15.2(d), and subject to Section 5.8, Purchaser may exercise all of its rights and remedies contemplated by Section 4.3.1, including the right to terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice. Such rights and remedies shall collectively be the sole and exclusive remedy of Purchaser with respect to such Owner Default as provided in Section 4.3.1(b)(iii).

(b) In the case of an Owner Default pursuant to Section 15.2(c), and subject to Section 5.8, this Agreement shall terminate in accordance with Section 3.3.5 without liability to either Party (except for any accrued but unpaid payment obligations and any

indemnification obligations under this Agreement). Such termination shall be the sole and exclusive remedy of Purchaser with respect to such Owner Default.

(c) In the case of an Owner Default pursuant to Section 15.2(f), and subject to Section 5.8, Purchaser may terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice. Such termination shall be the sole and exclusive remedy of Purchaser with respect to such Owner Default and any breach of Section 8.3(a) resulting from such Owner Default.

(d) In the case of an Owner Default pursuant to Section 15.2(h), and subject to Section 5.8, Purchaser may exercise all of its rights and remedies contemplated by Section 7.4, including the right to terminate this Agreement by written notice to Owner as of a date that is not less than ninety (90) days after the date of such notice if the Northern Pass Transmission Line is entirely out-of-service for the five (5)-year period following a Non-Excused Outage (which five (5)-year period shall not be subject to extension for any event of Force Majeure). Such rights and remedies shall collectively be the sole and exclusive remedy of Purchaser with respect to such Owner Default as provided in Section 7.4.4.

(e) Upon the written agreement of the Parties on the amount of the damages suffered by Purchaser as a result of an Owner Default, or the determination of such amount pursuant to the dispute resolution provisions herein, then, if Owner shall not have paid such amount by the date specified for payment in such written agreement or within fourteen (14) Business Days after the date of such determination, as applicable, Purchaser may exercise and enforce any and all of its rights and remedies under the Purchaser's Security Documents or against Purchaser's Lien.

(f) Subject to the limitations provided in Section 4.3.1(b)(iii), Section 7.4.4, Article 19 or this Section 15.4, as applicable, Purchaser may recover all damages suffered by Purchaser as a result of an Owner Default, including, for the avoidance of doubt, any costs or expenses (including reasonable attorneys' fees) reasonably incurred by Purchaser to recover any amounts owed to Purchaser by Owner under this Agreement.

(g) Purchaser may exercise and enforce any and all of its rights and remedies under the Owner Guaranty or any other financial assurances held by Purchaser.

(h) In the event the Parties agree in writing upon the amount of the damages suffered by Purchaser as a result of an Owner Default (i) due to a Non-Excused Outage or (ii) pursuant to Section 21.2, or such amount has been determined pursuant to the dispute resolution provisions herein, then, if Owner shall not have paid such amount by the date specified for payment in such written agreement or within fourteen (14) Business Days after the date of such determination, as applicable, Purchaser may deduct and setoff payment of such amount against any Transmission Service Payment.

(i) Purchaser may exercise any and all other rights and remedies that may be available to Purchaser at law or in equity, unless expressly prohibited or otherwise restricted by Article 19 or any other provision of this Agreement. Notwithstanding the foregoing sentence, Purchaser shall have no right to (i) terminate this Agreement based

upon an Owner Default, except as provided in clauses (a), (c) and (d) above, or (ii) any reduction of or offset against payments under this Agreement based upon an Owner Default, except as contemplated by Section 7.4.1, Section 8.1.4, Section 14.7, Section 15.4(h) and Section 16.4, as applicable.

Section 15.5. Disputes. Any Dispute over whether or not an Owner Default or Purchaser Default has occurred shall be resolved in accordance with Article 18.

ARTICLE 16

FORCE MAJEURE

Section 16.1. Definition.

(a) "Force Majeure" means an event or circumstance that prevents a Party from performing its obligations under this Agreement, which event or circumstance is not within the reasonable control of such Party. Such events or circumstances shall include the following, but only to the extent they satisfy the foregoing condition: actions or inactions of any Governmental Authority; acts of God; war, terrorism, riot or insurrection; blockades; embargoes; sabotage; epidemics; explosions and fires; hurricanes, floods, blizzards, ice storms, thunderstorms and other abnormal weather conditions; national or regional general strikes, lockouts or other labor disputes. Force Majeure shall not include (i) changes in market conditions that affect the demand for, or supply of, electrical energy or capacity or transmission service, (ii) the acts or omissions of a third party, including contractors, customers, vendors and sub-contractors, except to the extent resulting from Force Majeure, (iii) economic hardship or (iv) the financial inability of any Person to perform its obligations.

(b) A Party shall not be required to settle any strike, walkout, lockout or other labor dispute on terms that, in the sole judgment of such Party, are contrary to its interest. The settlement of strikes, walkouts, lockouts or other labor disputes shall be entirely within the discretion of the Party involved in such dispute.

Section 16.2. Conditions.

(a) If and to the extent a Party is prevented by Force Majeure from performing, in whole or part, its obligations under this Agreement and such claiming Party gives notice and details of the Force Majeure to the other Party as soon as practicable, then such claiming Party shall be excused from the performance of its obligations hereunder (other than the obligation to make any payments or comply with Article 17); provided that the suspension of performance due to Force Majeure shall be of no greater scope than is required by such Force Majeure and shall be of no greater duration than is consistent with clause (b) below.

(b) Such claiming Party shall use commercially reasonable efforts to (i) seek to avoid and (ii) mitigate or remedy any Force Majeure in a commercially reasonable timeframe consistent with Good Utility Practice. Subject to the limitations provided in Section 16.3, all costs and expenses incurred by Owner to comply with its obligations under

the foregoing sentence shall be recoverable under the Formula Rate in accordance with Article 8.

Section 16.3. Events of Loss.

(a) Owner shall notify Purchaser as soon as practicable, but in no event later than ten (10) days, after Owner becomes aware of a Loss Occurrence.

(b) The following provisions shall apply in the event of a Loss Occurrence during the Construction Phase:

(i) Promptly after, but no later than sixty (60) days following a Loss Occurrence, Owner shall prepare and submit to the Management Committee for review and approval a Construction Budget and Schedule inclusive of all projected Reconstruction Costs associated with such Loss Occurrence.

(ii) Subject to Purchaser's termination rights under Section 3.3.6 or Section 3.3.8, as applicable, and the rights of any Financing Party, Owner shall reconstruct or otherwise repair the Northern Pass Transmission Line in a manner consistent with Owner's rights and obligations under Section 5.1.2(a)(i) and Section 5.2.4(a); provided, however, that Owner shall not commence with such reconstruction or repair prior to the sixty-first (61st) day after the receipt by Purchaser's Manager of the proposed Construction Budget and Schedule described in clause (b)(i) above, unless the Management Committee shall have approved, or Purchaser shall have agreed in writing to reimburse Owner for, the costs associated therewith. Any delays in reconstruction or repair due to Owner's compliance with the proviso to the first sentence of this clause (b)(ii) shall not constitute a violation of Good Utility Practice.

(c) The following provisions shall apply in the event of a Loss Occurrence during the Operation Phase:

(i) Promptly after, but no later than sixty (60) days following, a Loss Occurrence Owner shall prepare and submit to the Management Committee for review and approval a budget and schedule that sets forth all Reconstruction Costs and the expected timeline to complete the work required to reconstruct or otherwise repair the Northern Pass Transmission Line (the "Reconstruction Plan"), together with a statement for informational purposes that sets forth in reasonable detail the unamortized Rate Base calculated as of the date of such Loss Occurrence (the "Rate Base Calculation"). At the request of Purchaser's Manager, Owner shall provide the Management Committee with access to, and copies of, all reasonably requested documentation concerning such Reconstruction Plan or Rate Base Calculation.

(ii) The Management Committee shall promptly review the proposed Reconstruction Plan, and may approve such Reconstruction Plan in whole or in part. If an Impasse occurs with respect to the proposed Reconstruction Plan (or any part thereof), then the Impasse shall not be resolved under the dispute resolution provisions herein, and instead, subject to Purchaser's termination rights under Section 3.3.9 or Section 3.3.10, as applicable, the proposed Reconstruction Plan, with any changes agreed upon by the Management Committee, shall be deemed to be (A) in effect upon the sixty-first (61st) day after the receipt by Purchaser's

Manager of such Reconstruction Plan and Rate Base Calculation and (B) approved by the Management Committee as of such date for purposes of Section 8.1.4(c)(i).

(iii) Subject to Purchaser's termination rights under Section 3.3.9 or Section 3.3.10, as applicable, and the rights of any Financing Party, Owner shall reconstruct or otherwise repair the Northern Pass Transmission Line in a manner consistent with Owner's rights and obligations under Section 16.2(b) and clause (c)(iv) below; provided, however, that Owner shall not commence with such reconstruction or repair prior to the sixty-first (61st) day after the receipt by Purchaser's Manager of the proposed Reconstruction Plan and the Rate Base Calculation described in clause (c)(i) above, unless the Management Committee shall have approved, or Purchaser shall have agreed in writing to reimburse Owner for, the costs associated therewith. Any delays in reconstruction or repair due to Owner's compliance with the proviso to the first sentence of this clause (c)(iii) shall not constitute a violation of Good Utility Practice.

(iv) Owner shall use commercially reasonable efforts not to exceed the budgeted amounts set forth in the Reconstruction Plan; provided, however, that, consistent with Section 16.2(b), all Reconstruction Costs, whether or not set forth in such Reconstruction Plan, shall be recoverable under the Formula Rate in accordance with Article 8.

Section 16.4. Extended Outages; Extended Term.

(a) If an event of Force Majeure in the United States renders the Northern Pass Transmission Line entirely out-of-service for more than three hundred sixty-five (365) consecutive days (an "Extended Outage"), then Purchaser shall have no obligation to pay the ROE portion of the Transmission Service Payment or depreciation expenses from and after the final day of such three hundred sixty-five (365)-day period until such time as the Northern Pass Transmission Line has been placed back in-service at an operating condition sufficient to enable the provision of Firm Transmission Service, but Purchaser shall continue to pay all other portions of the Transmission Service Payments, including the debt component, Taxes and O&M Costs, during such Extended Outage.

(b) Following an Extended Outage:

(i) the Term shall be extended for a period equal to the entire period of time during which the Northern Pass Transmission Line was out-of-service due to such Extended Outage; and

(ii) the ROE portion of the Transmission Service Payments and depreciation expenses shall resume and Owner shall recover the ROE on the remaining transmission investment and such depreciation, in each case, over the period commencing on such resumption date and ending on the last day of the penultimate year of the extended Term.

(c) From and after the first calendar month following the Commercial Operation Date, if an event of Force Majeure causes the availability of the Northern Pass Transmission Line ("Average Availability") to fall below the Minimum Average Availability, as measured over any calendar month, then the Term shall be extended for an

additional calendar month, except where the Term has already been extended for such unavailability of the Northern Pass Transmission Line under clause (b)(i) above.

(d) Any costs and expenses that are incurred during any extended Term contemplated by clause (b)(i) or (c) above shall be recoverable under the Formula Rate in accordance with Article 8.

(e) For purposes of this Section 16.4, the Average Availability for any measurement period shall be calculated using the arithmetic average of the Hourly Availability values for all hours in such measurement period.

Section 16.5. Insurance Proceeds. Subject to the rights of any Financing Party, if and to the extent Owner receives or is entitled to receive proceeds from insurance or other amounts payable in connection with any Force Majeure (including any Loss Occurrence), Owner shall then credit such amounts (excluding any proceeds of any liability insurance policy or any insurance proceeds or other amounts payable to any Financing Party, unless such amounts payable are permitted under the applicable Loan Documents to be applied to such Force Majeure) to Purchaser under the Formula Rate, net of reasonable fees (including attorneys' fees) and other expenses incurred by Owner in connection with the receipt and final collection of such amounts. Owner shall use commercially reasonable efforts to pursue the collection or recovery of any such amounts and otherwise seek to enforce any rights to which it is entitled with respect to any Force Majeure (including any Loss Occurrence).

ARTICLE 17

FINANCIAL ASSURANCES

Section 17.1. Parent Guaranty.

Section 17.1.1. Purchaser's Guaranty.

(a) Purchaser shall cause Hydro-Québec to execute and deliver to Owner, no later than the Execution Date, a payment guaranty, substantially in the form attached hereto as Attachment E-1, for the benefit of Owner (the "Purchaser Guaranty"), which Purchaser Guaranty shall guaranty payment of (i) all present and future amounts owed by Purchaser to Owner hereunder (excluding obligations owed by Purchaser to Owner for Decommissioning Costs); provided that the aggregate liability of Hydro-Québec for such amounts shall be subject to the Stated Cap set forth in the Purchaser Guaranty, which Stated Cap shall be equal to the Determined Cap determined in accordance with this Section 17.1.1 (the "Capped Guaranteed Obligations"), (ii) the Decommissioning Liquidated Damages, as provided in the Purchaser Guaranty, and (iii) certain costs of enforcement, as provided in the Purchaser Guaranty.

(b) In accordance with clauses (g) and (i) below, as applicable, Purchaser shall cause Hydro-Québec to reissue the Purchaser Guaranty with a revised Stated Cap from time to time. Upon the receipt by Owner of each Purchaser Guaranty that has been

reissued in compliance with clause (g) or (i) below, as applicable, the previously issued Purchaser Guaranty shall terminate, subject to clause (e) below.

(c) Subject to Section 23.1, Purchaser shall cause each Purchaser Guaranty to be and remain in full force and effect at all times from and after the commencement of the Construction Phase and until the earlier to occur of (i) the date on which the obligations guaranteed thereunder have been fully, finally and indefeasibly paid, or, with respect to the obligations guaranteed thereunder with respect to the payment of the Decommissioning Liquidated Damages, the termination date therefor, as set forth in the Purchaser Guaranty, and (ii) subject to clause (e) below, the date on which a Purchaser Guaranty shall have been reissued in compliance with clause (g) or (i) below, as applicable.

(d) The Determined Cap shall be an amount determined as follows:

(i) until the first Redetermination Date, the Determined Cap shall equal Fifty-Five Million U.S. Dollars (U.S. $55,000,000);

(ii) as of each Redetermination Date during the period commencing on the first Redetermination Date and ending on the last day of the Construction Phase, the Determined Cap shall equal (A) the Settlement Amount that, if applicable, would be payable upon an early termination of this Agreement as of such Redetermination Date, with the "Project Costs" component of the Settlement Amount to be determined by reference to all Project Costs that have been incurred by Owner with respect to the Northern Pass Transmission Line prior to such Redetermination Date (whether payable before or after such Redetermination Date, and including reasonable forecasts of such Project Costs to the extent the actual amounts thereof are unknown to Owner as of the date of the applicable Redetermination Certificate), and with the "Owner's Costs" component of the Settlement Amount to be determined by reference to (1) all amounts described in clauses (a) and (b) of the definition of "Owner's Costs" that have been incurred by Owner with respect to the Northern Pass Transmission Line prior to such Redetermination Date (whether payable before or after such Redetermination Date, and including reasonable forecasts of such amounts to the extent the actual amounts thereof are unknown to Owner as of the date of the applicable Redetermination Certificate), subject to the exclusions to such definition, plus (2) the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 5.2.3 concurrently with the delivery to the Management Committee of the most recent Construction Budget and Schedule for the upcoming fourteen (14) calendar months after such Redetermination Date; plus (B) the budgeted Construction Costs, as set forth in the most recent Construction Budget and Schedule for the upcoming fourteen (14) calendar months after such Redetermination Date; minus (C) the sum of all Capped Guaranteed Obligations paid by Hydro-Québec to Owner under any Purchaser Guaranty prior to the date of the applicable Redetermination Certificate; provided, however, that, if Purchaser shall have submitted any matter with respect to Estimated Wind-Down Costs to the Management Committee for resolution under Section 5.2.3(b) and the Management Committee shall not have resolved such matter prior to the date of such Redetermination Certificate, then, until the Management Committee shall have agreed upon such Estimated Wind-Down Costs (or such Estimated Wind-Down Costs shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), the Estimated

Wind-Down Costs shall be deemed equal to the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 5.2.3 concurrently with the delivery to the Management Committee of the most recent Construction Budget and Schedule for the upcoming fourteen (14) calendar months after such Redetermination Date. If the Estimated Wind-Down Costs are subsequently adjusted by the agreement of the Management Committee (or pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), then Purchaser shall cause Hydro-Québec to reissue the Purchaser Guaranty in accordance with clause (i) below. For the avoidance of doubt, the budgeted Construction Costs described in the foregoing clause (B) shall be subject to the approval of the Management Committee as and to the extent provided in Section 5.2.2(b).

(iii) as of each Redetermination Date during the Operation Phase, the Determined Cap shall equal (A) the Owner's Costs Plus EAFUDC that, if applicable, would be payable upon an early termination of this Agreement as of such Redetermination Date, with the "Owner's Costs" component of the Owner's Costs Plus EAFUDC to be determined by reference to (1) all amounts described in clauses (a) and (b) of the definition of "Owner's Costs" that have been incurred by Owner with respect to the Northern Pass Transmission Line prior to such Redetermination Date (whether payable before or after such Redetermination Date, and including reasonable forecasts of such amounts to the extent the actual amounts thereof are unknown to Owner as of the date of the applicable Redetermination Certificate), subject to the exclusions to such definition, plus (2) the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 6.4 concurrently with the delivery to the Management Committee of the Capital Plan for the upcoming Contract Year after such Redetermination Date; plus (B) the sum of (1) the budgeted amounts set forth in the Capital Plan for the upcoming Contract Year after such Redetermination Date, plus (2) the budgeted amounts set forth in the Multiyear Outlook for the second and third Contract Years after such Redetermination Date (the sum of the amounts set forth in the foregoing clauses (1) and (2), the "Budgeted Amount"); minus (C) the sum of all Capped Guaranteed Obligations paid by Hydro-Québec to Owner under any Purchaser Guaranty prior to the date of the applicable Redetermination Certificate; provided, however, that:

(1) if Purchaser shall have submitted any matter with respect to Estimated Wind-Down Costs to the Management Committee for resolution under Section 6.4(b) and the Management Committee shall not have resolved such matter prior to the date of such Redetermination Certificate, then, until the Management Committee shall have agreed upon such Estimated Wind-Down Costs (or such Estimated Wind-Down Costs shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), the Estimated Wind-Down Costs shall be deemed equal to the Estimated Wind-Down Costs set forth in the estimate thereof delivered to Purchaser under Section 6.4 concurrently with the delivery to the Management Committee of the most recent Annual Plan and Operating Budget for the upcoming Contract Year after such Redetermination Date;

(2) if the Management Committee shall not have approved such Capital Plan or Multiyear Outlook (or such Capital Plan or Multiyear Outlook

shall not have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto) prior to the date of such Redetermination Certificate, then, until the Management Committee shall have approved such Capital Plan or Multiyear Outlook (or such Capital Plan or Multiyear Outlook shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), the Budgeted Amount shall be deemed equal to the sum of the budgeted amounts for the upcoming three (3) Contract Years after such Redetermination Date, as set forth in (x) the Multiyear Outlook most recently approved by the Management Committee (or determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto) or (y) if no such Multiyear Outlook exists, then the Multiyear Outlook most recently delivered to the Management Committee under Section 6.3; and

(3) if the Estimated Wind-Down Costs, Capital Plan or Multiyear Outlook is subsequently adjusted by the agreement of the Management Committee (or pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto), then Purchaser shall cause Hydro-Québec to reissue the Purchaser Guaranty in accordance with clause (i) below.

(iv) in the case of each of clauses (d)(ii) and (d)(iii) above, (A) the adjustments required pursuant to Section 3.4(c) shall apply *mutatis mutandis* to the Determined Cap and (B) the dollar amount of the Determined Cap shall be rounded up to the nearest One Million Dollars ($1,000,000), unless such dollar amount is Zero Dollars ($0).

(e) Notwithstanding anything in this Section 17.1.1 to the contrary, if, prior to any Redetermination Date, a claim for Capped Guaranteed Obligations has been submitted by Owner to Hydro-Québec under any Purchaser Guaranty (an "Existing Guaranty") but not yet paid by Hydro-Québec thereunder (an "Outstanding Claim"), then such Existing Guaranty shall not terminate upon the reissuance of a new Purchaser Guaranty, but shall continue in full force and effect solely with respect to such Outstanding Claim and the costs of enforcement thereof, as provided in such Existing Guaranty and subject to the Stated Cap set forth in such Existing Guaranty (as reduced by the sum of all Capped Guaranteed Obligations paid by Hydro-Québec to Owner under such Existing Guaranty prior to such Redetermination Date ("Prior Claims")). With respect to the Purchaser Guaranty subsequently reissued by Hydro-Québec in accordance with clause (g) or (i) below for such Redetermination Date (which reissued Purchaser Guaranty shall be in addition to the Existing Guaranty until the Existing Guaranty terminates in accordance with this clause (e)), and for purposes of calculating the Determined Cap (as redetermined in accordance with clause (d) above) to be set forth in such reissued Purchaser Guaranty, the Determined Cap shall be reduced to the extent, if any, Hydro-Québec shall have accepted, in writing, liability for such Outstanding Claim prior to the reissuance of such Purchaser Guaranty. If and when Hydro-Québec pays the lesser of the (i) the entire Outstanding Claim (or the portion of such Outstanding Claim that satisfies in full such Outstanding Claim, as mutually agreed by Hydro-Québec and Owner or for which Hydro-Québec is found liable pursuant to the final order of a court of competent jurisdiction) and (ii) the Stated Cap set forth in such Existing Guaranty (as reduced by the sum of all Prior Claims) ("Satisfying Amount"), then, if and to the extent an additional adjustment is required to the Stated Cap set forth in such reissued Purchaser Guaranty, Purchaser shall cause Hydro-Québec

to reissue such Purchaser Guaranty in accordance with clause (i) below. If and when (A) Hydro-Québec pays the Satisfying Amount, together with the costs of enforcement thereof, as provided in such Purchaser Guaranty, or (B) Hydro-Québec is found not to be liable for such Outstanding Claim pursuant to the final order of a court of competent jurisdiction, then, in each case, the Existing Guaranty shall terminate.

(f) The amount of the Determined Cap, as redetermined as of each Redetermination Date, as provided in clause (d) above, shall be set forth in a certificate of Owner, showing the calculation thereof in reasonable detail (a "Redetermination Certificate"). With respect to each Redetermination Date during the Construction Phase, Owner shall deliver a Redetermination Certificate to Purchaser within thirty (30) days after the date on which Owner shall have delivered the applicable Construction Budget and Schedule to Purchaser's Manager under Section 5.2.2. With respect to each Redetermination Date during the Operation Phase, Owner shall deliver a Redetermination Certificate to Purchaser by the earlier to occur of (i) seventy-five (75) days after the date on which Owner shall have delivered the applicable Capital Plan and Multiyear Outlook to Purchaser's Manager under Section 6.3 and (ii) thirty (30) days after the date on which the Management Committee shall have approved such Capital Plan and Multiyear Outlook (or such Capital Plan and Multiyear Outlook shall have been determined pursuant to the dispute resolution provisions in this Agreement in the event of an Impasse with respect thereto). Purchaser promptly shall acknowledge such Redetermination Certificate and deliver such acknowledged Redetermination Certificate to Hydro-Québec.

(g) Subject to Section 23.1, Purchaser shall cause Hydro-Québec, following the receipt by Purchaser of each Redetermination Certificate (regardless of any Impasse or other Dispute with respect to the Redetermination Certificate), to reissue the Purchaser Guaranty, as provided herein, with a revised Stated Cap equal to the Determined Cap, as so redetermined in accordance with clause (d) above, but subject to clause (e) above, and as set forth in such Redetermination Certificate, which Purchaser Guaranty shall be effective as of the date of issuance. Provided that a Redetermination Certificate is provided to Purchaser, the failure of Purchaser to acknowledge such Redetermination Certificate, or of Hydro-Québec to reissue such Purchaser Guaranty with such revised Stated Cap, as provided in this clause (g), within forty-five (45) days following the receipt by Purchaser of such Redetermination Certificate, shall be deemed to be a termination by Purchaser of this Agreement under Section 3.3.8 or Section 3.3.10, as applicable, unless Section 3.3.6 is applicable.

(h) If Owner fails to provide any Redetermination Certificate required by clause (f) above within fifteen (15) days after the receipt by Owner of written notice of such failure from Purchaser, Purchaser may provide such Redetermination Certificate to Hydro-Québec, with a copy to Owner, and Purchaser shall cause Hydro-Québec thereafter to reissue the Purchaser Guaranty in accordance with clause (g) above, with a revised Stated Cap equal to the Determined Cap, as so redetermined in accordance with clause (d) above, but subject to clause (e) above, and as set forth in such Redetermination Certificate, which Purchaser Guaranty shall be effective as of the date of issuance. Owner shall be entitled to Dispute any amount set forth in such Redetermination Certificate in accordance with Section 18.1(b).

(i) Without limiting the provisions of Section 5.2.2(b) or Section 8.1.4(c), Purchaser's acknowledgement or issuance of a Redetermination Certificate or Hydro-Québec's issuance of a Purchaser Guaranty shall be without prejudice to any right or remedy that Purchaser may have under this Agreement to contest any amount set forth in a Redetermination Certificate, and none of the foregoing actions by Purchaser or Hydro-Québec shall be construed in any way to create a presumption that the Redetermination Certificate or Determined Cap is correct. Upon resolution of any Dispute as to whether or not the Determined Cap set forth in a Redetermination Certificate is mathematically correct or was calculated in accordance with clause (d) or (e) above, or resolution of any Impasse with respect to the Estimated Wind-Down Costs, Capital Plan or Multiyear Outlook, in each case, as contemplated by this Section 17.1.1, Purchaser shall cause Hydro-Québec to reissue the Purchaser Guaranty, as provided herein, with a revised Stated Cap equal to the Determined Cap, as so determined by the agreement of the Management Committee or pursuant to the dispute resolution provisions in this Agreement, but subject to clause (e) above, which Purchaser Guaranty shall be effective as of the date of issuance. The failure of Hydro-Québec to reissue such Purchaser Guaranty with such revised Stated Cap, as provided in this clause (i), within forty-five (45) days following the resolution of any such Dispute or Impasse, shall be deemed to be a termination by Purchaser of this Agreement under Section 3.3.8 or Section 3.3.10, as applicable, unless Section 3.3.6 is applicable.

Section 17.1.2.Owner's Guaranty. Owner shall (a) cause each of Northeast Utilities and NSTAR to execute and deliver to Purchaser, no later than the Execution Date, a payment guaranty, substantially in the form attached hereto as Attachment E-2, for the benefit of Purchaser (each an "Owner Guaranty"), and (b) subject to Section 23.1, cause each such Owner Guaranty to be and remain in full force and effect at all times from and after the Commercial Operation Date and until the amounts guaranteed thereunder have been fully, finally and indefeasibly paid. The Owner Guaranty to be executed and delivered by Northeast Utilities shall be in the maximum principal amount equal to Twenty-Five Million Dollars ($25,000,000) multiplied by the ratio of Northeast Utilities' beneficial ownership interest in Owner to the aggregate beneficial interests in Owner owned by Northeast Utilities and NSTAR, and the Owner Guaranty to be executed and delivered by NSTAR shall be in the maximum principal amount equal to Twenty-Five Million Dollars ($25,000,000) multiplied by the ratio of NSTAR's beneficial ownership interest in Owner to the aggregate beneficial interests in Owner owned by Northeast Utilities and NSTAR. Purchaser agrees to cooperate with Northeast Utilities and NSTAR, at their written request, to amend the Owner Guaranties from time to time to amend the maximum principal amount of each such Owner Guaranty in proportion to the respective beneficial ownership interests in Owner owned by Northeast Utilities and NSTAR, such that the aggregate principal amount of the Owner Guaranties issued by Northeast Utilities and NSTAR at all times shall equal Twenty-Five Million Dollars ($25,000,000) (less any amounts drawn under such Owner Guaranties).

Section 17.2. Purchaser's Lien.

Section 17.2.1.Security Documents. No later than the Distribution Date, as additional security for Owner's performance of its obligations hereunder, including payment of any indemnification obligations of Owner to Purchaser pursuant to Section 21.2, Owner shall (a) execute, deliver, and record a mortgage and security agreement and all other agreements,

documents, or instruments required or customary to provide Purchaser with a fully perfected security interest and mortgage lien in and to (i) the Northern Pass Transmission Line, and (ii) all real property rights and related personal property rights, contractual rights, Governmental Approvals, or other rights of Owner relating to the Northern Pass Transmission Line and the AC Upgrades (collectively, the "Purchaser Mortgage"), (b) execute and deliver a security agreement and all other agreements, documents, or instruments required or customary to provide Purchaser with a fully perfected security interest in and to (i) any material contracts entered into in connection with the Northern Pass Transmission Line or the AC Upgrades, and (ii) all of Owner's other assets relating to the Northern Pass Transmission Line and the AC Upgrades, including all personal property rights, contractual rights, Governmental Approvals, or other rights of Owner to develop, procure, construct, operate, and maintain the Northern Pass Transmission Line (collectively, the "Security Agreement"), and (c) cause each of its members to grant to Purchaser a present and continuing perfected lien on, and security interest in, all of the equity interests in Owner (collectively, the "Membership Pledges," and collectively with the Purchaser Mortgage and the Security Agreement, "Purchaser's Security Documents"). The Purchaser's Security Documents shall be based upon the agreements securing Owner's obligations under the Construction Loan Agreement, but shall not include any representations, warranties, covenants, or restrictions other than those that are reasonably required with respect to the creation, validity, perfection, protection or enforcement of Purchaser's security interests in the assets and property described in this Section 17.2.1 or as may otherwise be reasonably satisfactory to Purchaser, Owner, and the Financing Parties. The Purchaser's Security Documents shall provide that any such document may be assigned by Purchaser solely to the assignee of Purchaser pursuant to a permitted assignment of this Agreement. Subject to the rights of any Financing Parties, Owner shall cause the mortgage, liens and security interests created pursuant to Purchaser's Security Documents (collectively, "Purchaser's Lien") to be maintained in full force and effect at all times following the Distribution Date and until the later to occur of the expiration or earlier termination of the Term or the date on which any accrued but unpaid payment obligation of Owner to Purchaser hereunder shall have been fully, finally and indefeasibly satisfied. Promptly following such later date, Purchaser shall release the Purchaser's Lien. The granting of Purchaser's Lien shall not be to the exclusion of, or be construed to limit, the amount of any claims, causes of action or other rights accruing to Purchaser by reason of any breach by Owner under this Agreement, an Owner Default or the termination of this Agreement.

Section 17.2.2.Subordination. Purchaser's Lien shall be subordinate in right of priority and remedies only to the interests of the Financing Parties, to the extent of the Project Debt Obligations, but shall be superior in priority to all other indebtedness of Owner secured by the assets subject to the Purchaser's Security Documents. The subordination of Purchaser's Lien shall be effective on the terms and conditions set forth in Attachment F without necessity of the execution by Purchaser of further instruments to effectuate such subordination (provided that Purchaser's Security Documents shall be subject to the terms and conditions set forth in Attachment F), but Purchaser agrees to execute and deliver, at the request of any Financing Party, such documents or instruments as may be reasonably required to confirm such subordination on the terms and conditions set forth in Attachment F and otherwise on terms and conditions reasonably required by the Financing Parties. Solely for purposes of the automatic subordination provided for in this Section 17.2.2, the principal amount of the Project Debt Obligations to which Purchaser's Lien is subordinate shall be deemed to be equal to fifty percent (50%) of Owner's total capitalization; provided that any documents or instruments executed by

Purchaser, at the request of any Financing Party, pursuant to the second sentence of this Section 17.2.2 shall specify the maximum actual principal amount of the Project Debt Obligations (consistent with Owner's obligations under Section 5.6 and Section 8.3(a)) to which Purchaser's Lien is subordinate. No later than the Distribution Date, Purchaser shall execute and deliver, at the request of Hydro-Québec Lender, a subordination agreement or intercreditor agreement with Hydro-Québec Lender with respect to Purchaser's Lien on the terms and conditions set forth in Attachment F and otherwise reasonably satisfactory to Purchaser and Hydro-Québec Lender. In addition, no later than the date on which funds are initially distributed by the Term Loan Lender under the Term Loan Agreement, or, if applicable, by an Additional Lender under the loan and credit agreements entered into by Owner with respect to any Additional Financing that such Additional Lender commits to provide, Purchaser shall, at Owner's request, cooperate and diligently negotiate with each Term Loan Lender or such Additional Lender the form of a subordination agreement or intercreditor agreement with respect to Purchaser's Lien, substantially on the terms and conditions set forth in Attachment F, with such other terms and conditions as may be customary for transactions of a similar nature and as may be reasonably required by the Term Loan Lender or such Additional Lender (any such agreement, the "Subordination Agreement").

Section 17.2.3.Recording. Upon or promptly after the Distribution Date, the Parties shall file and record, at the expense of Owner, the Purchaser Mortgage. In addition, Owner hereby agrees to take such further action and execute such further instruments as may be reasonably requested by Purchaser to confirm and continue the validity, priority, and perfection of Purchaser's Lien, and agrees to cooperate with Purchaser in the execution and filing of, and hereby authorizes the execution and filing of, such financing statements under the Uniform Commercial Code or other Applicable Law, as may be requested by Purchaser or required by Applicable Law, upon or promptly after such date, and to confirm and continue the validity, priority, and perfection of Purchaser's Lien.

Section 17.2.4.Transfer of Governmental Approval. The Purchaser's Security Documents shall provide that, in the event Purchaser acts to obtain title (directly or indirectly) to the Northern Pass Transmission Line by exercise of its rights thereunder, Owner shall cooperate diligently with Purchaser in connection with the transfer to Purchaser of all Governmental Approvals necessary to construct, own or operate the Northern Pass Transmission Line.

ARTICLE 18

DISPUTE RESOLUTION

Section 18.1. Referral to the Management Committee.

(a) Either Party may refer a Dispute (other than a Dispute over the matters described in Section 13.2(b)(iii)(A), Section 13.2(b)(iii)(B) and Section 13.2(b)(iii)(C)) to the Management Committee by written notice to the other Party of such referral ("Dispute Notice"); provided that, following an Impasse with respect to any matter upon which the Managers were unable to reach agreement or any Dispute that the Managers

were unable to resolve, such matter or Dispute shall not be referred back to the Management Committee pursuant to this clause (a). Such Dispute Notice shall include a Position Statement. Each Party shall honor any reasonable request made by the other Party for information with regard to a Dispute.

(b) Subject to Section 18.2 and except as expressly provided otherwise in this Agreement, any Dispute that has not been timely resolved by the Management Committee, as provided in Section 13.9 (or any Dispute that may not be referred to the Management Committee, as described in clause (a) above), shall be finally resolved in accordance with Section 18.3.

(c) All negotiations pursuant to this Section 18.1 shall be deemed to be confidential and shall be treated as compromise and settlement negotiations, and no evidence with regard to any proposal made during such negotiations shall be admissible in any arbitration under Section 18.3 or in any other proceeding following such negotiations, including any FERC proceeding or filing contemplated by Section 18.2.

Section 18.2. Disputes to be Resolved by FERC. In the event a Dispute over any of the following matters is not resolved in accordance with Section 18.1(a), either Party shall have the right to file for relief with FERC, subject to Article 20, unless the Parties mutually agree to resolve such Dispute in accordance with Section 18.3 or by some other means:

(a) Any matter subject to challenge under Section 8.1.4;

(b) Any matter subject to challenge under Section 8.1.5;

(c) Any matter subject to challenge under Section 8.4(b);

(d) Any matter subject to challenge under Section 8.6(d);

(e) Any matter subject to challenge under Section 8.6(f);

(f) Any filing or Dispute under Article 9 or Article 10 (to the extent that Article 9 or Article 10 does not expressly require resolution under Section 18.3);

(g) Any matter subject to challenge under Article 20; or

(h) Any matter that is subject to the exclusive jurisdiction of FERC; provided that, in the event any Party objects to the reference of any such matter to FERC on the grounds that such matter is not subject to the exclusive jurisdiction of FERC, the matter shall be referred to FERC for resolution of the Dispute as to whether or not such matter is subject to the exclusive jurisdiction of FERC.

Nothing contained in this Agreement shall be construed as precluding a Party from filing any answer, protest or other opposition to any FERC filing made by the other Party, unless expressly prohibited under the terms of this Agreement.

Section 18.3. Arbitration.

Section 18.3.1. Arbitration of Technical Disputes.

(a) Within thirty (30) days after the Execution Date, the Parties shall propose the names of up to three (3) technical experts to act as Expert Arbitrators for Technical Disputes that may arise ("Expert Arbitrator Candidates"). A Party shall accept or reject any Expert Arbitrator Candidate proposed by the other Party within ten (10) Business Days after such proposal. The Parties shall continue to propose Expert Arbitrator Candidates until the panel of Expert Arbitrators is comprised of at least three (3) Expert Arbitrators (the "Panel"). The Parties shall agree upon the order of the Expert Arbitrators on the Panel. If any Expert Arbitrator is no longer available to serve on the Panel or ceases to satisfy the criteria for an Expert Arbitrator, then the Parties shall promptly agree upon a suitable replacement.

(b) Once the period for resolution of a Dispute submitted to the Management Committee, as set forth in Section 18.1, has terminated without a resolution of such Dispute, or earlier if both Parties agree, and in the event the Dispute is technical in nature (a "Technical Dispute"), the Technical Dispute may be submitted by either Party (with concurrent notice of such submission to the other Party (a "Technical Dispute Notice")) for arbitration by an Expert Arbitrator (an "Expert Arbitration"). Any Party involved in the Technical Dispute may object to reference of the Technical Dispute to an Expert Arbitrator on the grounds that such Technical Dispute is not appropriate for resolution by Expert Arbitration by giving notice of such objection to the other Party within ten (10) Business Days after the receipt by such Party of the Technical Dispute Notice, whereupon an Expert Arbitrator selected in accordance with clause (c) below shall determine whether or not such Dispute is a Technical Dispute appropriate for resolution by Expert Arbitration. In the event the Expert Arbitration determines that the Dispute is a Technical Dispute appropriate for resolution by Expert Arbitration, such Dispute shall be resolved in accordance with this Section 18.3.1. Absent such determination, the Technical Dispute shall be finally resolved in accordance with Section 18.3.2.

(c) The Parties shall promptly confer as to which of the Expert Arbitrators on the Panel have the appropriate expertise to hear the Technical Dispute. Promptly thereafter, the Party referring the Technical Dispute to Expert Arbitration shall contact the first Expert Arbitrator on the Panel who the Parties mutually agree has such expertise. If such Expert Arbitrator has any financial interest in the outcome of any Dispute or is unavailable to serve in a timely fashion, then the other Expert Arbitrators on the Panel who the Parties mutually agree have such expertise shall be contacted in order until an Expert Arbitrator without any financial interest in the outcome of the Technical Dispute is available to hear the Technical Dispute in a timely fashion. If, for any reason, all of the Expert Arbitrators on the Panel without any financial interest in the outcome of any Dispute are unavailable to hear the Technical Dispute, or the Parties fail to agree that any of the available Expert Arbitrators on the Panel have the appropriate expertise to hear the Technical Dispute, then Parties shall have ten (10) days to agree upon a suitable Expert Arbitrator. If the Parties fail to agree, within such ten (10)-day period, upon an Expert Arbitrator to hear the Technical Dispute, then, on the request of either Party, the International Chamber of Commerce ("ICC") Center for Expertise shall appoint an Expert Arbitrator to hear the Technical Dispute.

(d) The arbitration of the Technical Dispute shall be conducted in New York, New York (or such other place to which the Parties mutually agree in writing), in accordance with ICC Rules for Expertise. The language of the arbitration of the Technical Dispute and of all documentation in the arbitration shall be English. The Expert Arbitrator may request information and documents from the Parties that he or she determines to be reasonably necessary to resolve the Technical Dispute. The Expert Arbitrator shall review evidence and other submissions by the Parties and, unless the Parties mutually agree otherwise, shall hold a one (1)-day hearing. The Parties and the Expert Arbitrator shall use commercially reasonable efforts to have the Expert Arbitrator render a final award as soon as possible, and if practicable, within ninety (90) days after his or her appointment. Such time period may be extended by the Expert Arbitrator for good cause shown or by the written agreement of both Parties. The award of the Expert Arbitrator shall be in writing and shall briefly state the findings of fact and conclusions of law upon which it is based; it shall be final and binding on the Parties, and may be entered and enforced in any court having jurisdiction.

Section 18.3.2.Arbitration for Other Disputes.

(a) Disputes not covered by Section 18.3.1 shall be finally resolved by arbitration in accordance with the Rules of the ICC (the "Rules"), as in effect from time to time.

(b) The place of arbitration shall be New York, New York (or such other place to which the Parties mutually agree in writing). The language of the arbitration and of all documentation in the arbitration shall be English. If the amount in controversy is Five Million Dollars ($5,000,000) or less (including all claims and counterclaims), then the Dispute shall be decided by a single arbitrator who shall be agreed upon by the Parties within twenty (20) days after the receipt by a Party of a copy of a written demand for arbitration from the other Party. If the amount in controversy is more than Five Million Dollars ($5,000,000) (including all claims and counterclaims), then the Dispute shall be decided by three (3) neutral and impartial arbitrators, one of whom shall be appointed by each of the Parties in accordance with the Rules, and the third arbitrator, who shall chair the arbitral tribunal, shall be appointed by the Party-appointed arbitrators within fifteen (15) days after the appointment of the second arbitrator. In the event any arbitrator is not appointed within the time limit provided herein, such arbitrator shall be appointed by the ICC. Any arbitrator appointed by the ICC shall be a retired judge or a practicing attorney, with not less than fifteen (15) years of experience with large complex cases and who, if practicable, is an experienced arbitrator of disputes involving transmission facilities. All arbitrators shall be fluent in the English language. The Parties, with the consent of the arbitrator(s), shall be entitled to discovery of documents directly related to the issues in Dispute. The arbitrator(s) may also request additional information from the Parties. The arbitration shall be governed by the Federal Arbitration Act, 9 U.S.C. § 1 *et seq*. The award of the arbitrator(s) shall be in writing and shall briefly state the findings of fact and conclusions of law upon which it is based; it shall be final and binding on the Parties, and may be entered and enforced in any court having jurisdiction.

Section 18.3.3.Arbitral Awards; Fees and Expenses. No Expert Arbitrator or arbitrator is empowered to award damages in excess of compensatory damages and each Party

expressly waives and foregoes any right to damages, claims, or remedies identified in Article 19. The fees and expenses of the Expert Arbitrator or arbitrator(s), as applicable, and the costs of the facilities required for the Expert Arbitration or arbitration, as applicable, shall be paid equally by the Parties, unless the award specifies a different division of such costs and expenses. Each Party shall be responsible for its own expenses, including attorneys' fees. Each of the Parties shall be afforded adequate opportunity to present information in support of its position on the Dispute being arbitrated.

Section 18.3.4.Confidentiality. All Disputes shall be resolved in a confidential manner. The Expert Arbitrator or arbitrator(s), as applicable, shall agree to hold any information received during the Expert Arbitration or arbitration, as applicable, in the strictest of confidence and shall not disclose to any non-party the existence, contents or results of the Expert Arbitration or arbitration, as applicable, or any other information about such Expert Arbitration or arbitration, as applicable. No Party shall disclose or permit the disclosure of any information about the evidence adduced or the documents produced by the other Party in such proceedings or about the existence, contents or results of the proceeding, except as (x) may be required by Applicable Law or a Governmental Authority, (y) may be necessary in an action in aid of such proceedings or for enforcement of an arbitral award, and (z) reasonably required for enforcement or interpretation of this Agreement by FERC to the extent any Dispute is brought to FERC as provided in Section 18.2. Before making any disclosure permitted by the foregoing clauses (x) and (y), the Party intending to make such disclosure shall give the other Party reasonable written notice in advance of the intended disclosure and afford the other Party a reasonable opportunity to protect its interests. The following information shall not be subject to the restrictions provided for in this Section 18.3.4:

(a) Information that is a matter of public knowledge at the time of its disclosure or is thereafter published in or otherwise ascertainable from a source available to the public without breach of this Agreement;

(b) Information that is obtained from a Person other than by or as a result of unauthorized disclosure; or

(c) Information that, prior to the time of disclosure, had been independently developed or obtained by the disclosing Party or its Affiliates independent of information obtained as a result of unauthorized disclosure.

Section 18.3.5.Arbitration Proceedings. Each Party shall proceed to conclude the Expert Arbitration or arbitration, as applicable, proceeding as quickly as reasonably possible. If a Party refuses to participate in any such proceeding, then the other Party may petition any court of law having proper jurisdiction for an order to compel Expert Arbitration or arbitration, as applicable. All costs and expenses incurred by the petitioning Party in enforcing such participation obligation shall be paid for by the refusing Party.

Section 18.3.6.Exclusive Remedies. Except for any Dispute to be resolved pursuant to Section 18.2, Expert Arbitration or arbitration, as applicable, under this Section 18.3 shall be the exclusive remedy for all Disputes arising under this Agreement that are not resolved by the Management Committee.

Section 18.4. Equitable Remedies. Notwithstanding anything herein to the contrary, prior to the appointment of an Expert Arbitrator under Section 18.3.1 or the arbitrator or arbitrators under Section 18.3.2, either Party may seek temporary injunctive relief in a court of law with jurisdiction over the Parties to maintain the status quo or prevent irreparable harm. Without prejudice to such provisional remedies as may be available under the jurisdiction of a court, the arbitrator(s) shall have full authority to grant provisional remedies or order the Parties to request that a court modify or vacate any temporary or preliminary relief issued by such court, and to award damages for the failure of any Party to respect the orders of the arbitrator(s) to that effect.

ARTICLE 19

LIMITATION OF REMEDIES

NOTWITHSTANDING ANYTHING IN THIS AGREEMENT TO THE CONTRARY, NEITHER PARTY NOR ANY OF THEIR RESPECTIVE AGENTS, SUBCONTRACTORS, REPRESENTATIVES OR AFFILIATES SHALL BE LIABLE TO THE OTHER PARTY FOR PUNITIVE, CONSEQUENTIAL, SPECIAL, MULTIPLE, EXEMPLARY, INCIDENTAL OR INDIRECT DAMAGES OF ANY NATURE, INCLUDING THE FOLLOWING: LOSS OF REVENUE OR PROFIT FROM THE WHOLESALE SALE OF POWER; ADVERSE RATE IMPACTS ON RETAIL OR WHOLESALE CUSTOMERS OF EITHER PARTY OR THEIR RESPECTIVE AFFILIATES; LOSS OF A TAX BENEFIT OR TAX CREDIT; LOSS OF USE DAMAGES (EXCEPT AS EXPRESSLY CONTEMPLATED IN Section 4.3.1 OR Section 7.4 OR FOR ANY DIRECT DAMAGES SUFFERED BY PURCHASER AS A RESULT OF A BREACH BY OWNER OF ITS OBLIGATIONS UNDER Section 6.2, Article 10, Section 11.2 OR Article 12); COST OF REPLACEMENT POWER; COST OF REPLACEMENT TRANSMISSION SERVICE (EXCEPT AS EXPRESSLY CONTEMPLATED IN Section 4.3.1 OR Section 7.4); OR CLAIMS OF CUSTOMERS FOR LOSS OF POWER OR PRODUCTION, IN EACH CASE, ARISING OUT OF OR RELATING TO THE PERFORMANCE OF THIS AGREEMENT, AND WHETHER SUCH LIABILITY IS CLAIMED IN CONTRACT OR TORT (INCLUDING NEGLIGENCE AND STRICT LIABILITY, WARRANTY, FAILURE OF GOOD UTILITY PRACTICE OR ANY OTHER LEGAL OR EQUITABLE THEORY).

FOR THE AVOIDANCE OF DOUBT, THE PARTIES ACKNOWLEDGE AND AGREE THAT Section 4.3.1 OR Section 7.4 PROVIDE THE SOLE AND EXCLUSIVE REMEDIES FOR ANY LOSS OF USE CONTEMPLATED BY Section 4.3.1 OR Section 7.4 AND NOTHING IN Section 6.2, Article 10, Section 11.2 OR Article 12 SHALL SUPERSEDE, SUPPLEMENT OR AMEND SUCH SOLE AND EXCLUSIVE REMEDIES.

THIS Article 19 IS IN ADDITION TO THE SPECIFIC LIMITATIONS ON REMEDIES REFERENCED IN Article 15.

ARTICLE 20

MODIFICATION OF THIS AGREEMENT

Section 20.1. Certain Changes to Formula Rate. Notwithstanding anything herein to the contrary, nothing contained in this Agreement shall be construed as affecting in any way the right of Owner to make a unilateral filing at any time under Section 205 of the Federal Power Act or the regulations promulgated thereunder to change the Formula Rate. In the event of any such Section 205 filing, Purchaser shall have the right to oppose Owner's proposed changes to the Formula Rate in any FERC proceeding. In addition, notwithstanding anything herein to the contrary, nothing contained in this Agreement shall be construed as affecting in any way the right of Purchaser to file a complaint at any time under Section 206 of the Federal Power Act seeking to change the Formula Rate. Notwithstanding the foregoing provisions, no filing by Owner under Section 205 of the Federal Power Act or by either Party under Section 206 of the Federal Power Act shall be permitted to the extent that it is inconsistent with the terms and conditions of this Agreement.

Section 20.2. Other Modifications. The Parties specifically intend and acknowledge and agree that, except as otherwise expressly provided in this Agreement, (a) this Agreement shall not be subject to amendment or other modification, absent the written agreement of both Parties and (b) neither Party shall be permitted to make a filing with FERC under any provision of the Federal Power Act or the regulations promulgated thereunder that seeks to amend or otherwise modify, or requests FERC to amend or otherwise modify, any provision of this Agreement at any time during the Term, except to implement an amendment or other modification to this Agreement that has been reduced to writing and signed by both Parties. In addition, to the extent any third party, or FERC acting *sua sponte* seeks to amend or otherwise modify, or requests FERC to amend or otherwise modify, any provision of this Agreement, the standard of review for any proposed amendment or other modification shall be the "public interest" standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956), and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), and as further defined in *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1 of Snohomish County*, 128 S.Ct. 2733 (2008) and *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 130 S.Ct. 693 (2010).

ARTICLE 21

INDEMNIFICATION

Section 21.1. Purchaser Indemnity. Purchaser shall indemnify, defend and hold harmless Owner and Owner's Affiliates and their respective officers, directors, shareholders, managers, members, partners, agents, employees, representatives, and permitted successors and assigns (each, an "Owner Indemnified Party"), from and against any and all claims, demands, suits, proceedings, judgments, losses, liabilities, damages, in each case, resulting from any third-party claims, together with any costs and expenses (including reasonable attorneys' fees) incurred by any such Owner Indemnified Party, and arising out of (a) the performance by the OASIS Provider or the OASIS Administrator of capacity release functions and transmission resales

pursuant to this Agreement or (b) the gross negligence, willful misconduct or criminal misconduct of Purchaser. Purchaser shall have no obligations under the immediately preceding sentence to the extent any claims, demands, suits, proceedings, judgments, losses, liabilities, damages, costs and expenses (including reasonable attorneys' fees) incurred by any such Owner Indemnified Party are caused by or arise from the gross negligence, willful misconduct or criminal misconduct of, or breach or default of contract by, an Owner Indemnified Party.

Section 21.2. Owner Indemnity. Owner shall indemnify, defend and hold harmless Purchaser and Purchaser's Affiliates and their respective officers, directors, shareholders, managers, members, partners, agents, employees, representatives, and permitted successors and assigns (each, a "Purchaser Indemnified Party"), from and against any and all claims, demands, suits, proceedings, judgments, losses, liabilities, damages, in each case, resulting from any third-party claims, together with any costs and expenses (including reasonable attorneys' fees) incurred by any such Purchaser Indemnified Party, and arising out of the gross negligence, willful misconduct or criminal misconduct of Owner, other than Excluded Claims. Owner shall have no obligations under the immediately preceding sentence to the extent any claims, demands, suits, proceedings, judgments, losses, liabilities, damages, costs and expenses (including reasonable attorneys' fees) incurred by any such Purchaser Indemnified Party are caused by or arise from the gross negligence, willful misconduct or criminal misconduct of, or breach of contract by, a Purchaser Indemnified Party.

Section 21.3. Procedures. Promptly after the receipt by any Person seeking indemnification under this Article 21 (the "Indemnified Party") of written notice of the assertion of any claim by a third party with respect to any matter in respect of which indemnification may be sought hereunder (a "Third Party Claim"), the Indemnified Party shall give written notice (the "Indemnification Notice") to the Party from which indemnification is sought (the "Indemnifying Party"), and shall thereafter keep the Indemnifying Party reasonably informed with respect thereto; provided, however, that the failure of the Indemnified Party to give the Indemnifying Party notice as provided herein shall not relieve the Indemnifying Party of any of its obligations hereunder, except to the extent that the Indemnifying Party is materially prejudiced by such failure. The Indemnifying Party shall be entitled to assume the defense of any Third Party Claim by written notice to the Indemnified Party of such intention given within thirty (30) days after the receipt by the Indemnifying Party of the Indemnification Notice; provided, however, that counsel selected by the Indemnifying Party shall be reasonably satisfactory to the Indemnified Party. The Indemnifying Party shall be liable for the fees and expenses of counsel employed by the Indemnified Party for any period during which the Indemnifying Party has not assumed the defense of any Third Party Claim (other than during any period during which the Indemnified Party has failed to give notice of such Third Party Claim as provided above). If the Indemnifying Party shall assume the defense of the Third Party Claim, then the Indemnifying Party shall not compromise or settle such Third Party Claim without the prior written consent of the Indemnified Party, which consent shall not be unreasonably withheld, delayed or conditioned; provided, however, that the Indemnified Party shall have no obligation to consent to any settlement that (a) does not include, as an unconditional term thereof, the giving by the claimant or the plaintiff of a release of the Indemnified Party from all liability with respect to such Third Party Claim or (b) involves the imposition of equitable remedies or the imposition of any material obligations on such Indemnified Party other than financial obligations for which such Indemnified Party is indemnified hereunder. As long as the Indemnifying Party is contesting any

such Third Party Claim on a timely basis, the Indemnified Party shall not pay, compromise or settle any claims brought under such Third Party Claim. Notwithstanding the assumption by the Indemnifying Party of the defense of any Third Party Claim as provided in this Section 21.3, the Indemnified Party shall be permitted to participate in the defense of such Third Party Claim and to employ counsel at its own expense (it being understood that the Indemnifying Party controls such defense); provided, however, that, if the defendants in any Third Party Claim shall include both an Indemnifying Party and any Indemnified Party, and such Indemnified Party shall have reasonably concluded that counsel selected by the Indemnifying Party has a conflict of interest because of the availability of different or additional defenses to such Indemnified Party, such Indemnified Party shall then have the right to select separate counsel to participate in the defense of such Third Party Claim on its behalf, at the expense of the Indemnifying Party; provided that the Indemnifying Party shall not be obligated to pay the expenses of more than one separate counsel for all Indemnified Parties, taken together.

Section 21.4. Defenses. If the Indemnifying Party shall fail to notify the Indemnified Party of its desire to assume the defense of any Third Party Claim within the prescribed period of time, or shall notify the Indemnified Party that it will not assume the defense of any such Third Party Claim, then the Indemnified Party may assume the defense of any such Third Party Claim, in which case it may do so acting in good faith and otherwise in such manner as it may deem appropriate, and the Indemnifying Party shall be bound by any determination made in such Third Party Claim.

Section 21.5. Cooperation. The Indemnified Party and the Indemnifying Party shall each cooperate fully (and shall each cause its Affiliates to cooperate fully) with the other in the defense of any Third Party Claim pursuant to this Article 21. Without limiting the generality of the foregoing, each such Person shall furnish the other such Person (at the expense of the Indemnifying Party) with such documentary or other evidence as is then in its or any of its Affiliates' possession, as may reasonably be requested by the other Person for the purpose of defending against any such Third Party Claim.

Section 21.6. Recovery. The amount of any indemnity hereunder shall be reduced by any insurance proceeds (including any proceeds of any liability insurance policy or any insurance proceeds or other amounts payable to any Financing Party, unless such amounts payable are permitted under the applicable Loan Documents to be applied to the Third Party Claim) actually recovered by the Indemnified Party in connection with the Third Party Claim. If at any time subsequent to the receipt by an Indemnified Party of an indemnity payment hereunder, such Indemnified Party (or any Affiliate thereof) receives any recovery, settlement or other similar payment with respect to the Third Party Claim for which it received such indemnity payment (a "Recovery"), such Indemnified Party shall then promptly pay to the Indemnifying Party the amount of such Recovery, less any expenses incurred by such Indemnified Party (or its Affiliates) in connection with such Recovery, but in no event shall any such payment exceed the amount of such indemnity payment.

Section 21.7. Subrogation. To the extent the Indemnifying Party makes or is required to make any indemnity payment to the Indemnified Party, the Indemnifying Party shall be entitled to exercise, and shall be subrogated to, any rights and remedies (including rights of indemnity, rights of contribution and other rights of recovery) that the Indemnified Party or any

of its Affiliates may have against any other Person with respect thereto, whether directly or indirectly related. The Indemnified Party shall permit the Indemnifying Party to use the name of the Indemnified Party and the names of the Indemnified Party's Affiliates in any transaction or in any proceeding or other matter involving any of such rights or remedies; and the Indemnified Party shall take such actions as the Indemnifying Party may reasonably request for the purpose of enabling the Indemnifying Party to perfect or exercise its right of subrogation hereunder.

ARTICLE 22

REPRESENTATIONS, WARRANTIES AND COVENANTS

Section 22.1. Mutual Representations and Warranties. Each Party hereby represents and warrants to the other Party that all of the statements in this Section 22.1 are true and correct as of the Execution Date (unless another date is expressly indicated) and will be true and correct as of the Effective Date and as of the Commercial Operation Date, but not as of any other date:

(a) It has knowledge and experience in financial matters and in the electric industry that enable it to evaluate the merits and risks of this Agreement and the transactions contemplated hereby, and is capable of evaluating such merits and risks and assuming such risks. It is acting for its own account, has made its own independent decision to enter into this Agreement as to whether this Agreement is appropriate and proper for it based upon its own judgment, is not relying upon the advice or recommendations of the other Party in doing so, and understands and accepts the terms, conditions, and risks of this Agreement and the transactions contemplated hereby;

(b) It has entered into this Agreement in connection with the conduct of its business;

(c) The other Party is not acting as a fiduciary or an advisor with respect to this Agreement or the transactions contemplated hereby;

(d) It is not subject to an Insolvency Event and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it that could result in the occurrence of an Insolvency Event with respect to it; and

(e) It is an entity subject to the procedures and substantive provisions of the Bankruptcy Code applicable to U.S. corporations or limited liability companies, as applicable, generally.

Section 22.2. Additional Representations and Warranties of Purchaser. Purchaser hereby represents and warrants to Owner that all of the statements in this Section 22.2 are true and correct as of the Execution Date (unless another date is expressly indicated) and, except for the statement in Section 22.2(h), will be true and correct as of the Effective Date and as of the Commercial Operation Date, but not as of any other date:

(a) Purchaser is duly organized, validly existing, and in good standing under the laws in the State of Delaware and is qualified in each other jurisdiction where the failure to so qualify would have a Material Adverse Effect on Purchaser, and Purchaser has all requisite power and authority to conduct its business, own its properties, and to execute, deliver, and perform its obligations under this Agreement;

(b) Purchaser has all requisite corporate power and authority necessary to authorize the execution and delivery of this Agreement and the performance of its obligations hereunder, and to consummate the transactions contemplated hereby, and this Agreement has been duly executed and delivered by Purchaser;

(c) Assuming due authorization, execution and delivery by Owner, this Agreement constitutes Purchaser's legal, valid and binding obligation enforceable against Purchaser in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization and other laws of general application relating to or affecting creditors' rights generally and to general principles of equity (regardless of whether considered in a proceeding in equity or at law);

(d) No legal proceeding is pending or, to its knowledge, threatened against Purchaser or any of its Affiliates that could have a Material Adverse Effect on Purchaser;

(e) No event with respect to Purchaser has occurred or is continuing that would constitute a Purchaser Default, and no Purchaser Default will occur as a result of Purchaser entering into or performing its obligations under this Agreement;

(f) The execution, delivery and performance of this Agreement by Purchaser does not and will not (i) violate any provisions of its certificate of incorporation or bylaws, or any Applicable Law; or (ii) violate, or result in any breach of, or constitute any default under, any agreement or instrument to which it is a party or by which it or any of its properties may be bound or affected;

(g) No actions, Consents, notifications, waivers, orders and filings are necessary with respect to the execution, delivery and performance of this Agreement by Purchaser; and

(h) To the best of Purchaser's knowledge, the Canadian Approvals and the Operational Approvals constitute all of the actions, Consents, notifications, waivers, orders and filings that are necessary to commence construction of the Québec Line in a manner consistent with Attachment A.

(i) Purchaser is in compliance with all Applicable Laws, except such noncompliance as could not reasonably be expected to have a Material Adverse Effect on Purchaser. Purchaser has not received any written notice that it is under investigation with respect to a violation of any Applicable Law that could reasonably be expected to have a Material Adverse Effect on Purchaser.

Section 22.3. Additional Representations and Warranties of Owner. Owner hereby represents and warrants to Purchaser that all of the statements in this Section 22.3 are true and correct as of the Execution Date (unless another date is expressly indicated) and, except for the statement in Section 22.3(g),will be true and correct as of the Effective Date and as of the Commercial Operation Date, but not as of any other date:

(a) Owner is duly organized, validly existing, and in good standing under the laws in the State of New Hampshire and is qualified in each other jurisdiction where the failure to so qualify would have a Material Adverse Effect on Owner, and Owner has all requisite power and authority to conduct its business, own its properties, and to execute, deliver, and perform its obligations under this Agreement;

(b) Owner has all requisite limited liability company power and authority necessary to authorize the execution and delivery of this Agreement and the performance of its obligations hereunder, and to consummate the transactions contemplated hereby, and this Agreement has been duly executed and delivered by Owner;

(c) Assuming due authorization, execution and delivery by Purchaser, this Agreement constitutes Owner's legal, valid and binding obligation enforceable against Owner in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization and other laws of general application relating to or affecting creditors' rights generally and to general principles of equity (regardless of whether considered in a proceeding in equity or at law);

(d) No legal proceeding is pending or, to its knowledge, threatened against Owner or any of its Affiliates that could have a Material Adverse Effect on Owner;

(e) No event with respect to Owner has occurred or is continuing that would constitute an Owner Default, and no Owner Default will occur as a result of Owner entering into or performing its obligations under this Agreement;

(f) The execution, delivery and performance of this Agreement by Owner does not and will not (i) violate any provisions of its articles of organization or operating agreement, or any Applicable Law; or (ii) violate, or result in any breach of, or constitute any default under, any agreement or instrument to which it is a party or by which it or any of its properties may be bound or affected;

(g) To the best of Owner's knowledge, the Owner Approvals and the Operational Approvals constitute all of the actions, Consents, notifications, waivers, orders and filings that are necessary with respect to the execution, delivery and performance of this Agreement by Owner, other than the AC Upgrade Approvals; and

(h) Owner is in compliance with all Applicable Laws, except such noncompliance as could not reasonably be expected to have a Material Adverse Effect on Owner. Owner has not received any written notice that it is under investigation with respect to a violation of any Applicable Law that could reasonably be expected to have a Material Adverse Effect on Owner.

Section 22.4. NO OTHER REPRESENTATIONS OR WARRANTIES. THE REPRESENTATIONS AND WARRANTIES OF OWNER SET FORTH IN Section 22.1 AND Section 22.3 ARE OWNER'S SOLE REPRESENTATIONS AND WARRANTIES ASSOCIATED WITH THE NORTHERN PASS TRANSMISSION LINE AND ARE MADE IN LIEU OF ALL OTHER REPRESENTATIONS, WARRANTIES AND GUARANTEES, EXPRESS OR IMPLIED, ASSOCIATED WITH THE NORTHERN PASS TRANSMISSION LINE, INCLUDING REPRESENTATIONS OR WARRANTIES AS TO MERCHANTABILITY, USAGE, SUITABILITY OR FITNESS FOR ANY PARTICULAR PURPOSE. THE FOREGOING SENTENCE SHALL NOT BE CONSTRUED IN ANY WAY TO LIMIT OWNER'S EXPRESS OBLIGATIONS UNDER THIS AGREEMENT.

ARTICLE 23

TRANSFER OF INTERESTS

Section 23.1. No Transfer of Interests.

(a) Any (i) direct or indirect change of control of either Party (whether voluntary or by operation of law), (ii) sale, transfer or other disposition of all or substantially all of the assets of either Party or (iii) except as provided in Section 23.3, assignment, transfer or other disposition of, whether to one or more assignees or transferees, all or any portion of either Party's rights, interests or obligations under this Agreement (each of the foregoing, a "Transfer"), shall require the prior written consent of the other Party, which consent shall not be unreasonably withheld, delayed or conditioned when viewed in light of all reasonable considerations, including the security or other financial assurances to be provided by on or behalf of any proposed successor or assign (including the net worth and creditworthiness of the issuer) and the availability and terms of any consent required from any Financing Party in connection with such Transfer. Any Transfer in contravention of this Article 23 shall be null and void.

(b) If Owner consents to a Transfer by Purchaser pursuant to this Section 23.1, then, upon such Transfer, including (i) the assumption, in writing by the Transferee, of Purchaser's obligations under this Agreement with respect to the Transferred portion of this Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (ii) delivery to Owner of any replacement security or other financial assurances to be provided by or on behalf of such Transferee, then, provided that a Purchaser Default shall not have occurred and be continuing, (x) the obligations of Purchaser (and of Hydro-Québec under the Purchaser Guaranty) shall terminate to the extent of the Transferred portion of this Agreement (it being understood that the Stated Cap shall be reduced in proportion to the Transferred portion of this Agreement), and Purchaser and Hydro-Québec shall be fully, finally, and unconditionally released from all liability associated therewith to the extent of the Transferred portion of this Agreement, and (y) at the request of Purchaser, Owner shall execute and deliver, to Purchaser or Hydro-Québec, a full, final, and unconditional release of the Purchaser Guaranty, in such form as Purchaser may reasonably request, with respect to the Transferred portion of this Agreement.

(c) If Purchaser consents to a Transfer by Owner pursuant to this Section 23.1, then, upon such Transfer, including (i) the assumption, in writing by the Transferee, of Owner's obligations under this Agreement with respect to the Transferred portion of this Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (ii) delivery to Purchaser of any replacement security or other financial assurances to be provided by or on behalf of such Transferee, then, provided that an Owner Default shall not have occurred and be continuing, (x) the obligations of Owner (and of Northeast Utilities and NSTAR under the Owner Guaranties and the Membership Pledges) shall terminate to the extent of the Transferred portion of this Agreement (it being understood that the aggregate liability of Northeast Utilities and NSTAR under the Owner Guaranties shall be reduced in proportion to the Transferred portion of this Agreement), and Owner, Northeast Utilities and NSTAR shall be fully, finally, and unconditionally released from all liability associated therewith to the extent of the Transferred portion of this Agreement, and (y) at the request of Owner, Purchaser shall execute and deliver, to Owner, Northeast Utilities or NSTAR, a full, final, and unconditional release of the Owner Guaranties and the Membership Pledges, in such form as Owner may reasonably request, with respect to the Transferred portion of this Agreement. For the avoidance of doubt, neither the Purchaser Mortgage nor the Security Agreement shall not terminate upon any Transfer by Owner pursuant to this Section 23.1, unless otherwise agreed in writing by Purchaser.

Section 23.2. Exceptions. Notwithstanding Section 23.1, consent shall not be required for any of the following:

(a) Any (i) change of control of Owner or (ii) transfer or other disposition of all or substantially all of the assets of Owner, in each case, resulting from a collateral assignment in favor of a Financing Party in accordance with Section 23.3;

(b) Any change of control of Owner resulting from the direct or indirect transfer of interests in Northeast Utilities or NSTAR; or

(c) Any change of control of Purchaser resulting from the direct or indirect transfer of interests in Hydro-Québec.

Section 23.3. Collateral Assignment. Owner shall be entitled, without restriction, to make one or more assignments of this Agreement for purposes of collateral security or any or all of its rights and benefits hereunder to or for the benefit of any and all Financing Parties, or grant to or for the benefit of any and all Financing Parties a lien on, or security interest in, any right, title or interest in all or any part of Owner's rights hereunder for the purpose of the financing or successive refinancing of the ownership, development, engineering, construction or operation of the Northern Pass Transmission Line; provided, however, that such assignment for purposes of collateral security shall recognize Purchaser's rights under this Agreement on terms and conditions as may be customary for financings of a similar nature and reasonably requested by any Financing Party. To facilitate Owner's obtaining of financing or successive refinancing for the ownership, development, engineering, construction or operation of the Northern Pass Transmission Line, Purchaser shall cooperate with Owner and shall execute and deliver such consents, acknowledgements, direct agreements or similar documents as may be customary for financings of a similar nature and reasonably requested by any Financing Party. Purchaser shall

also, at Owner's request, cause Hydro-Québec to cooperate with Owner to execute and deliver such consents, acknowledgements, direct agreements or similar documents as may be customary for financings of a similar nature and reasonably requested by any Financing Party.

ARTICLE 24

MISCELLANEOUS

Section 24.1. Governing Law. This Agreement and each of its provisions shall be governed by, and construed in accordance with, the laws of the State of New York without reference to its conflict of law rules other than Section 5-1401 of the New York General Obligations Law.

Section 24.2. Entire Agreement. This Agreement, together with the Attachments, constitutes the entire agreement and understanding among the Parties with respect to all subjects covered hereby and thereby and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters.

Section 24.3. Severability. Except as otherwise provided in Section 2.2, (a) in the event any part of this Agreement is held to be illegal, invalid or unenforceable to any extent, the legality, validity and enforceability of the remainder of this Agreement shall not be affected thereby, and shall remain in full force and effect and shall be enforced to the greatest extent permitted by Applicable Law and (b) with respect to any provision found to be illegal, invalid or unenforceable by an arbitrator having jurisdiction, the Parties shall endeavor to replace such invalid, illegal or unenforceable provision with the valid, legal and enforceable provision that achieves, as nearly as practicable, the commercial intent of this Agreement (as it may be amended from time to time).

Section 24.4. Notices. All notices, billings, requests, demands, waivers, consents and other communications under this Agreement shall be in writing and shall be effective (a) upon personal delivery thereof, including by overnight mail or courier service, with a record of receipt, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon the fourth (4th) day after mailing, (c) in the case of notice by facsimile for any communications other than billings, upon transmission; provided that such facsimile transmission is promptly confirmed by either of the methods set forth in the foregoing clause (a) or (b), in each case, addressed to each Party and copy party hereto at its address set forth below or at such other address as a Party may from time to time designate by written notice to the other Party pursuant to this Section 24.4, (d) in the case of notice by facsimile for billings only (but not any other communication, including any subsequent demand notice for any unpaid amounts), upon receipt of confirmation of successful transmission, but without any further requirement for evidence of receipt or confirmation by either of the methods set forth in the foregoing clause (a) or (b), or (e) in the case of notice by electronic mail for billings only (but not any other communication, including any subsequent demand notice for any unpaid amounts), upon transmission, without any requirement for evidence of receipt or confirmation by either of the methods set forth in the foregoing clause (a) or (b); provided that the Party delivering such notice did not receive any notice of unsuccessful or delayed transmission. A notice given in

connection with this Section 24.4 but received on a day other than a Business Day, or after business hours in the situs of receipt, shall be deemed to be received on the next Business Day.

If to Owner:

Northern Pass Transmission LLC
c/o Northeast Utilities Service Company
Attention: James A. Muntz, President
107 Selden Street
Berlin, Connecticut 06037
United States of America
Facsimile: (860)665-6717
Email: muntzja@nu.com

With a copy to:

Northern Pass Transmission LLC
c/o Northeast Utilities Service Company
Attention: Senior Vice President and General Counsel
56 Prospect Street
Hartford, Connecticut 06103
United States of America
Facsimile: (860)728-4581
Email: butlegb@nu.com

For billing purposes only:

Northern Pass Transmission LLC
c/o Northeast Utilities Service Company
Attention: Manager – Transmission Rates
107 Selden Street
Berlin, Connecticut 06037
United States of America
Facsimile: (860)665-2609
Email: coopelm@nu.com

If to Purchaser:

H.Q. Hydro Renewable Energy, Inc.
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada
H2Z 1A4
Attention: Christian G. Brosseau, President
Facsimile: (514)289-5484
Email: brosseau.christian@hydro.qc.ca

For billing purposes only:

H.Q. Hydro Renewable Energy, Inc.
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada
H2Z 1A4
Attention: Brigitte Benicy, Billing Manager
Facsimile: (514)289-6867
Email: benicy.brigitte@hydro.qc.ca

Section 24.5. Waiver; Cumulative Remedies. Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but such waiver shall not be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by any Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be, or construed as, a subsequent waiver of, or estoppel with respect to, the same or any other term or by Applicable Law. Except as otherwise provided in Section 14.3(b), the failure of or delay on the part of either Party to enforce or insist upon compliance with or strict performance of any term or condition of this Agreement, or to take advantage of any of its rights thereunder, shall not constitute a waiver or relinquishment of any such terms, conditions, or rights, but the same shall be and remain at all times in full force and effect. Except as otherwise provided herein, the remedies provided in this Agreement are cumulative and not exclusive of any remedies provided by law or in equity.

Section 24.6. Confidential Information. Each Party hereby agrees that it shall not disclose, or cause to be disclosed, to third parties any Confidential Information with respect to the other Party or any material or information identified as Critical Energy Infrastructure Information (other than to a disclosing Party's Affiliates and its and their respective counsel, directors, officers, employees, lenders, advisors or consultants, in each case, who have a need to know such information and have agreed to keep such information confidential). Each Party shall be responsible for ensuring that any Person to whom it discloses any Confidential Information shall comply with the restrictions in this Section 24.6. The restrictions in this Section 24.6 shall not apply (w) to the extent disclosure is required by Applicable Law or the requirements of a Governmental Authority, (x) to the extent reasonably deemed by the disclosing Party to be required or desirable in connection with regulatory proceedings (including proceedings relating to FERC or any other national, federal, provincial, state or regulatory agency), (y) to the extent reasonably deemed by the disclosing Party to be required to be disclosed in connection with a Dispute between the Parties, or the defense of any litigation or dispute, or (z) as approved for release or disclosure by the other Party. In the event disclosure is made pursuant to this Section 24.6, the disclosing Party shall use reasonable efforts to minimize the scope of any disclosure and advise recipients of the confidentiality restrictions provided herein. Notwithstanding the foregoing, this Section 24.6 shall not apply to the following information:

(a) Information that is a matter of public knowledge at the time of its disclosure or is thereafter published in or otherwise ascertainable from a source available to the public without breach of this Section 24.6;

(b) Information that is obtained from a Person other than by or as a result of unauthorized disclosure; or

(c) Information that, prior to the time of disclosure, had been independently developed or obtained by the disclosing Party or its Affiliates independent of information obtained as a result of unauthorized disclosure.

Section 24.7. No Third-Party Rights. Except for any Financing Parties contemplated by Section 23.3 and any Owner Indemnified Party or Purchaser Indemnified Party contemplated by Article 21, the Parties do not intend for this Agreement to confer a third-party beneficiary status or rights of action upon any Person whatsoever other than the Parties and their permitted successors and assigns, and nothing contained herein, either express or implied, shall be construed to confer upon any Person, other than the Parties and their permitted successors and assigns, any rights of action or remedies under this Agreement or in any manner, or any duty, standard of care, or liability with respect thereto. This Agreement does not create third-party rights.

Section 24.8. Permitted Successors and Assigns. This Agreement shall be binding upon and inure to the benefit of each of the Parties and their successors, legal representatives and assigns.

Section 24.9. Relationship of the Parties. This Agreement shall not be construed as creating an association, joint venture, trust or partnership between the Parties or as imposing any partnership obligation or liability upon either Party. Except as contemplated by Article 10 or Section 15.3(b), neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

Section 24.10. Construction. No presumption shall operate in favor of or against either Party as a result of any responsibility for drafting this Agreement.

Section 24.11. Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Parties acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

Section 24.12. Survival. The provisions of Section 3.3, Section 3.4, Section 3.5, Section 3.6, Article 9, Article 13 (if and to the extent required for purposes of determining the Decommissioning Plan and Decommissioning Estimate, as provided in Section 9.3), Article 14, Article 15, Section 17.2.1, Article 18, Article 19, Article 20, Article 21 and this Article 24 shall survive the expiration or earlier termination of this Agreement.

Section 24.13. Language. All notices, requests, demands, waivers, consents and other communications between Owner and Purchaser under this Agreement shall be conducted in English.

Section 24.14. Headings and Table of Contents. The headings of the articles and sections of this Agreement and the Table of Contents are inserted for purposes of convenience only, and shall not be construed to affect the meaning or construction of any of the provisions hereof.

Section 24.15. Waiver of Immunities. The Parties acknowledge and agree that this Agreement and the transactions contemplated hereby constitute a commercial transaction. To the extent a Party (including any assignees of a Party's rights or obligations under this Agreement) may be entitled, in any jurisdiction, to claim for itself, or any of its assets, revenues or properties, sovereign or other immunity, as the case may be, from service of process, suit, the jurisdiction of any court or arbitral tribunal, attachment (whether in aid of execution or otherwise) or enforcement of a judgment (interlocutory or final) or award or any other legal process in a matter arising out of or relating to this Agreement, each Party agrees not to claim or assert, and hereby waives, such immunity. Without limiting the generality of the foregoing, each Party agrees that the waivers set forth in this Section 24.15 shall have the fullest scope permitted under the Immunities Act and under any other Applicable Law related to sovereign immunity.

[*Remainder of Page Intentionally Left Blank*]

IN WITNESS WHEREOF, Owner and Purchaser have executed this Agreement as of the Execution Date.

OWNER:

NORTHERN PASS TRANSMISSION LLC

By: James A. Muntz
Name: James A. Muntz
Title: President - Northern Pass Transmission LLC

PURCHASER:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: _____
Name: _____
Title: _____

IN WITNESS WHEREOF, Owner and Purchaser have executed this Agreement as of the Execution Date.

OWNER:

NORTHERN PASS TRANSMISSION LLC

By: _____
Name: _____
Title: _____

PURCHASER:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: _____
Name: CHRISTIAN G. BROSSEAU
Title: PRESIDENT

ATTACHMENT A

HVDC Transmission Project

I. Technical Design of the Northern Pass Transmission Line

1. HVDC Line:

- Transmission Line Voltage Level: +/-300 kV
- Approximate Length: 140 miles
- Transmission Line Construction: Overhead line
- Connections/Terminuses: The northern terminus of the HVDC Line will interconnect with the Québec Line at the U.S. Border. The southern terminus of the HVDC Line will be at the DC/AC converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire.

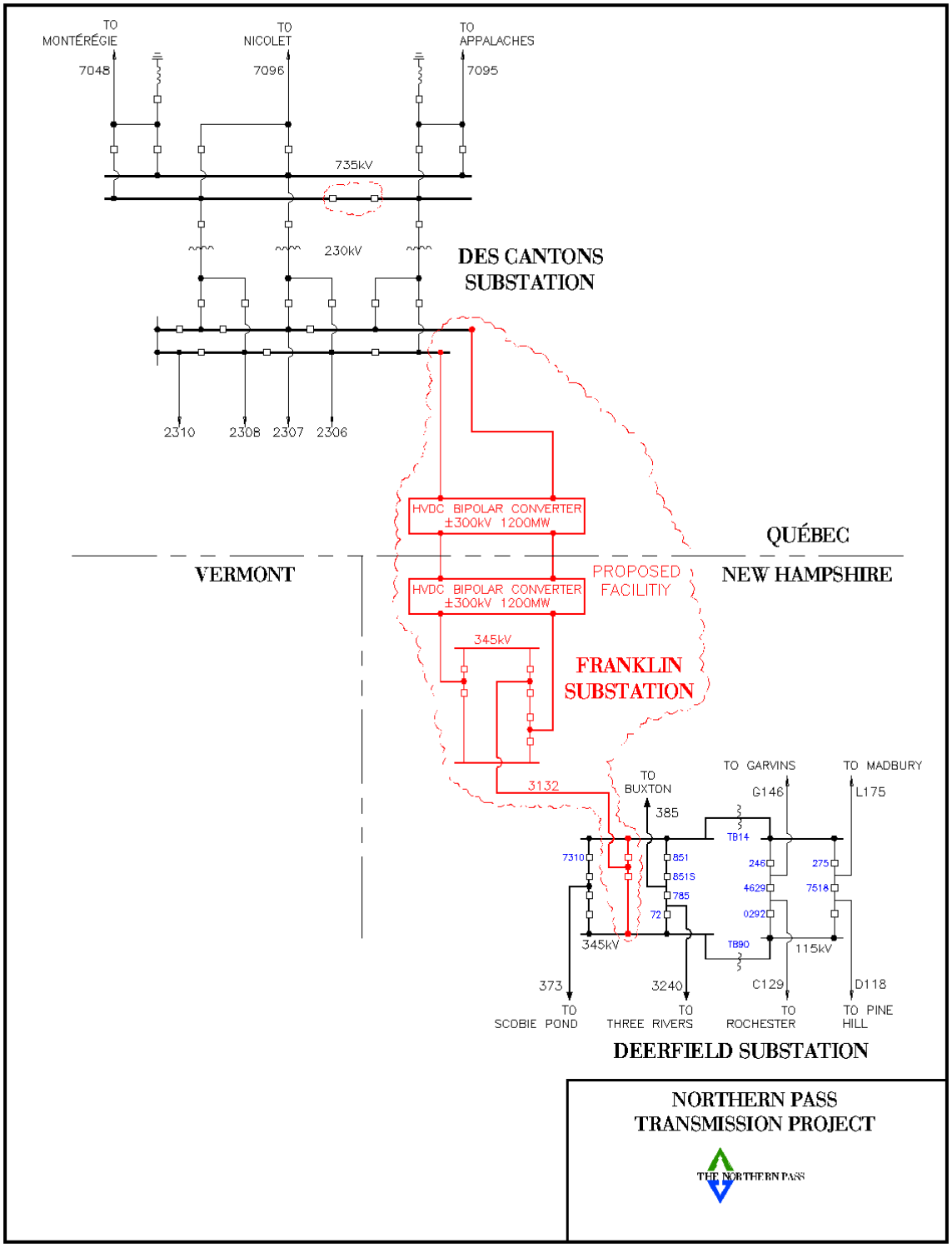
2. AC Line:

- Transmission Line Voltage Level: 345 kV
- Approximate Length: 43 miles
- Transmission Line Construction: Overhead line
- Connections/Terminuses: The northern terminus of the AC Line will be at the Franklin substation at the DC/AC converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire. The southern terminus of the AC Line will be at the Deerfield substation in the State of New Hampshire.

3. DC/AC Converter Station:

- The DC/AC converter station to be located near the Webster substation in the City of Franklin in the State of New Hampshire will be designed and constructed in accordance with the Design Capability in order to support bidirectional DC power flows over the Northern Pass Transmission Line to and from the 345 kV AC transmission system operated by ISO-NE.

II. One-Line Diagram of the HVDC Transmission Project



ATTACHMENT B

Formula Rate Sheet

I. Methodology

This formula sets forth the method that Owner shall use to determine its Revenue Requirement for the Northern Pass Transmission Line and AC Upgrades under the Transmission Service Agreement, dated as of October 4, 2010, and is subject to all of the terms and conditions of such Agreement.

The Revenue Requirement under the Agreement shall be derived through an annual Formula Rate calculation effective for the first Contract Year and each subsequent Contract Year based upon the estimated costs of the Northern Pass Transmission Line and the AC Upgrades. An annual true-up shall be performed by recalculation of the estimated costs for the first Contract Year and each subsequent Contract Year based upon actual cost information as reported in Owner's FERC Form 1 for that year or as set forth in Owner's books and records.

II. Definitions

Capitalized terms not otherwise defined elsewhere in the Agreement and as used in this Attachment B have the following definitions:

- *Administrative and General Expense* will equal Owner's expenses, as recorded in FERC Account Nos. 920 – 935, excluding FERC Account Nos. 924, 928 and 930.1.

- *Amortization of Investment Tax Credits* will equal Owner's credits, as recorded in FERC Account No. 411.4.

- *Amortization of Regulatory Asset – Pre-COD Expenses* will equal the total amortization expense related to those costs incurred by Owner before the Commercial Operation Date that are not included in FERC Account No. 107 – Construction Work in Progress (including the costs associated with AC Upgrades that are placed in service before the Commercial Operation Date), plus the Carrying Charges on these amounts from the date such costs are incurred until the Commercial Operation Date, as recorded in the appropriate FERC Account.

- *Asset Retirement Obligation (Decommissioning)* will equal the asset retirement cost for transmission plant recorded in FERC Account No. 359.1 and the asset retirement obligation recorded in FERC Account No. 230.

- *Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant* will equal Owner's transmission plant, general plant, and intangible plant depreciation expense as recorded in FERC Account No. 403. The annual depreciation expense for an asset comprising part of the Northern Pass Transmission Line as of the Commercial Operation Date will be computed using the depreciable life of the asset, as defined in Section 8.2 of the Agreement. Depreciation will begin on the in-service date of the Northern Pass Transmission Line. An asset comprising part of a capital addition that is placed-in-service after the Commercial Operation Date will be depreciated, for ratemaking purposes, using the depreciable life of the asset, as defined in Section 8.2 of the Agreement. For any asset that is retired prior to the lesser of its depreciable life, as defined in Section 8.2 of the Agreement, or the completion of forty (40) years from the Commercial Operation Date, the remaining net book value and cost of removal for such asset will be collected over the then-remaining contract life through a recalculation of the depreciation rate applied to the remaining plant balance and reflecting the retirement of the asset. Such Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant will exclude Depreciation Expense associated with Asset Retirement Obligation (Decommissioning).

- *Depreciation Expense associated with Asset Retirement Obligation (Decommissioning)* will equal Owner's depreciation expense, as recorded in FERC Account No. 403, specifically related to Asset Retirement Obligation (Decommissioning).

- *Depreciation Reserve for Transmission Plant, General Plant, and Intangible Plant* will equal the Owner's reserve balance associated with Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant, as recorded in FERC Account No. 108. Such Depreciation Reserve for Transmission Plant, General Plant, and Intangible Plant will exclude Depreciation Reserve associated with Asset Retirement Obligation (Decommissioning).

- *Depreciation Reserve associated with Asset Retirement Obligation (Decommissioning)* will equal Owner's reserve balance related to Depreciation Expense associated with Asset Retirement Obligation (Decommissioning), as recorded in FERC Account No. 108.

- *General Plant* will equal Owner's gross plant balance, as recorded in FERC Account Nos. 389 – 399.

- *Insurance Cost* will equal Owner's expenses, as recorded in FERC Account No. 924.

- *Intangible Plant* will equal Owner's intangible plant balance, as recorded in FERC Accounts Nos. 301 – 303.

- *Levelized Annual Decommissioning Payment* will equal the sum of the Levelized Monthly Decommissioning Payments that Section 9.3.3(a) of the Agreement specifies be included in the Formula Rate for the applicable Contract Year, unless a separate

rate is established for the recovery of Net Decommissioning Costs pursuant to Section 9.3.1(c) of the Agreement.

- *Miscellaneous Revenues (such as Rents Received from Electric Property)* will equal Owner's revenues, as recorded in FERC Account Nos. 454 and 456.1, excluding the revenues received by Owner from Purchaser under the Agreement. This includes revenue received by Owner from third parties for their use of Owner's real or personal property associated with the Northern Pass Transmission Line that is recorded in FERC Account No. 454, and revenue received by Owner from third parties for resales of Firm Transmission Service and non-firm Additional Transmission Service over the Northern Pass Transmission Line that is recorded in FERC Account No. 456.1.

- *Operation and Maintenance Expense* will equal Owner's expenses, as recorded in FERC Account Nos. 560, 561.5 – 561.8, 562 – 564, 566, and 568 – 576.5.

- *Payroll Taxes* will equal those payroll expenses, as recorded in Owner's FERC Account Nos. 408.1 and 409.1.

- *Plant Held for Future Use* will equal Owner's balance in FERC Account No. 105.

- *Plant Materials and Supplies* will equal the Owner's balance, as recorded in FERC Account No. 154.

- *Prepayments* will equal Owner's prepayment balance, as recorded in FERC Account No. 165.

- *Regulatory Asset – Asset Retirement Obligation (Decommissioning)* will equal the total amounts recorded in a subaccount within FERC Account No. 182 for the Net Decommissioning Costs.

- *Regulatory Asset – Pre-COD Expenses* will equal the total costs incurred by Owner before the Commercial Operation Date that are not included in FERC Account No. 107 – Construction Work in Progress (including the costs associated with AC Upgrades that are placed in service before the Commercial Operation Date), plus the Carrying Charges on these amounts (calculated using Owner's weighted cost of capital, based upon the Weighted Cost of Equity (as determined under Section III.A.2. below) and the Owner's Weighted Cost of Long-term Debt (as determined under Section III.B. below)) from the date such costs are incurred until the Commercial Operation Date. Such costs will be included in a subaccount within FERC Account No. 182. This account will be amortized over a three (3)-year period beginning on the Commercial Operation Date.

- *Right-of-Way (Rental) Expense* will equal Owner's expense, as recorded in FERC Account No. 567.

- *Scheduling, System Control and Dispatch Service Expense* will equal Owner's expense, as recorded in FERC Account Nos. 561.1 – 561.4.

- *Total Accumulated Deferred Income Taxes* will equal the net of Owner's deferred tax balances, as recorded in FERC Account Nos. 281 – 283 and Owner's deferred tax balances, as recorded in FERC Account No. 190, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FAS 109. Such Total Accumulated Deferred Income Taxes will exclude any deferred income tax amounts associated with the Asset Retirement Obligation (Decommissioning) and the Regulatory Asset – Asset Retirement Obligation (Decommissioning).

- *Total Municipal Tax* will equal Owner's expenses, as recorded in FERC Account Nos. 408.1 and 409.1.

- *Transmission Plant* will equal Owner's gross plant balance, as recorded in FERC Account Nos. 350 – 359. Such Transmission Plant will exclude any amounts recorded in FERC Account No. 359.1.

- *Transmission Support Expense* will equal Owner's expenses, as recorded in FERC Account No. 565.

III. Calculation of Revenue Requirement

The Revenue Requirement for the Northern Pass Transmission Line and AC Upgrades will equal the sum of the following Owner components:

(A) Return on Equity

(B) Return on Long-term Debt

(C) Federal Income Taxes associated with Return on Equity

(D) State Income Taxes associated with Return on Equity

(E) Depreciation Expense

(F) Amortization of Investment Tax Credits

(G) Municipal Tax Expense

(H) Payroll Tax Expense

(I) Operation and Maintenance Expense

(J) Transmission Administrative and General Expense

(K) Taxes and Fees Charge

(L) Right-of-Way (Rental) Expense

(M) Scheduling, System Control and Dispatch Service Expense

(N) Amortization of Regulatory Asset – Pre-COD Expenses

(O) Levelized Annual Decommissioning Payment

(P) Transmission Support Expense

(Q) Miscellaneous Revenues (such as Rents Received from Electric Property)

A. *Return on Equity* will equal the product of the Transmission Investment Base ("Rate Base") (as determined under Section III.A.1. below) and the Weighted Cost of Equity (as determined under Section III.A.2. below).

1. Transmission Investment Base

The Rate Base will consist of items (i) through (x) below. The average balance (beginning and end of year) will be used to calculate each of these items.

(i) Transmission Plant, plus

(ii) General Plant, plus

(iii) Intangible Plant, plus

(iv) Plant Held for Future Use, less

(v) Depreciation Reserve, less

(vi) Accumulated Deferred Income Taxes, plus

(vii) Regulatory Asset – Pre-COD Expenses, plus

(viii) Prepayments, plus

(ix) Plant Materials and Supplies, plus

(x) Cash Working Capital

Definitions of Rate Base Items:

(i) *Transmission Plant* will equal the balance of Owner's investment in Transmission Plant.

(ii) *General Plant* will equal Owner's balance of investment in General Plant.

(iii) *Intangible Plant* will equal Owner's balance of investment in Intangible Plant.

(iv) *Plant Held for Future Use* will equal the balance of Owner's Plant Held for Future Use.

(v) *Depreciation Reserve* will equal Owner's Depreciation Reserve for Transmission Plant, General Plant and Intangible Plant.

(vi) *Accumulated Deferred Income Taxes* will equal Owner's balance of Total Accumulated Deferred Income Taxes.

(vii) *Regulatory Asset – Pre-COD Expenses* will equal Owner's balance of Regulatory Asset – Pre-COD Expenses.

(viii) *Prepayments* will equal Owner's electric balance of Prepayments.

(ix) *Plant Materials and Supplies* will equal Owner's balance of Plant Materials and Supplies.

(x) *Cash Working Capital* will be a twelve and one half percent (12.5%) allowance (forty-five (45) days divided by three hundred sixty (360) days) of Operation and Maintenance Expense, Administrative and General Expense, and Transmission Support Expense.

2. The Weighted Cost of Equity will be calculated based upon an assumed capital structure of 50% equity throughout the Term of the Agreement, and will equal the product of:

(a) ROE, as set forth in Section 8.4 of the Agreement, and

(b) Assumed equity ratio of 50%.

B. *Return on Long-term Debt* will equal the product of Rate Base (as determined in Section III.A.1. above) and Owner's Weighted Cost of Long-term Debt. Owner's Weighted Cost of Long-term Debt will equal the product of:

(a) Owner's weighted average embedded cost to maturity (adjusted to reflect any (i) premiums, (ii) discounts, (iii) issuances expenses, and (iv) losses and gains on reacquired debt) of Owner's long-term debt then outstanding, calculated using a beginning and end of the year average, and

(b) Assumed debt ratio of 50% throughout the Term of the Agreement.

C. *Federal Income Taxes associated with Return on Equity* will equal the product of:

(a) $$\frac{(A + ((B + C) / D)) \times FT}{1 - FT}$$

where A is the Return on Equity (as determined in Section III.A. above), B is Amortization of Investment Tax Credits (as determined in Section III.F. below), C is the equity component of AFUDC included in the Depreciation Expense (as determined in Section III.E. below), D is Rate Base (as determined in Section III.A.1. above) and FT is the statutory Federal Income Tax Rate levied by the Federal Government for Income Taxes, and

(b) Rate Base (as determined in Section III.A.1. above).

D. *State Income Taxes associated with Return on Equity* will equal the product of:

(a) $$\frac{(A + ((B + C) / D) + \text{Federal Income Tax Rate above}) \times ST}{1 - ST}$$

where A is the Return on Equity (as determined in Section III.A. above), B is Amortization of Investment Tax Credits (as determined in Section III.F. below), C is the equity component of AFUDC included in the Depreciation Expense (as determined in Section III.E. below), D is Rate Base (as determined in Section III.A.1. above) and ST is the statutory State(s) Income Tax Rate(s) levied by the State Government(s) for Income Taxes, and

(b) Rate Base (as determined in Section III.A.1. above).

E. *Depreciation Expense* will equal Owner's Depreciation Expense for Transmission Plant, General Plant, and Intangible Plant.

F. *Amortization of Investment Tax Credits* will equal Owner's electric Amortization of Investment Tax Credits.

G. *Municipal Tax Expense* will equal Owner's electric Total Municipal Tax expense.

H. *Payroll Tax Expense* will equal Owner's electric Payroll Tax expense.

I. *Operation and Maintenance Expense* will equal Owner's Operation and Maintenance Expenses.

J. *Transmission Administrative and General Expenses* will equal the sum of Owner's (a) Administrative and General Expense, (b) Insurance Cost, (c) Expenses included in FERC Account No. 928 related to FERC Assessments, (d) any other Federal and State transmission-related expenses or assessments in FERC Account No. 928 and (e) specific transmission-related expenses included in FERC Account No. 930.1.

K. *Taxes and Fees Charge* will include any fee or assessment imposed by any Governmental Authority on service provided by Owner under the Agreement other than Income Taxes, Total Municipal Taxes, and Payroll Taxes.

L. *Right-of-Way (Rental) Expense* will equal the expense paid by Owner for right-of-way access.

M. *Scheduling, System Control and Dispatch Service Expense* will equal the expenses for scheduling, system control and dispatch services incurred by Owner, as recorded in Owner's FERC Form 1, Account Nos. 561.1 – 561.4.

N. *Amortization of Regulatory Asset – Pre-COD Expenses* will equal Owner's amortization expense associated with those costs recorded to the Regulatory Asset – Pre-COD Expenses account.

O. *Levelized Annual Decommissioning Payment* will equal the Levelized Annual Decommissioning Payment.

P. *Transmission Support Expense* will equal the expenses incurred and paid by Owner for transmission support, net of any associated revenues or refunds received from third parties.

Q. *Miscellaneous Revenues (such as Rents Received from Electric Property)* will equal Owner's Miscellaneous Revenues.

IV. Future Revisions to FERC Uniform System of Accounts (USA) and FERC Form 1 Requirements

If FERC prescribes an addition, deletion, or modification ("Revision") to an account in its Uniform System of Accounts (USA) and/or to its designation or description of an item in its FERC Form 1 and the Revision affects the revenue recovery under this Formula Rate described in this Schedule, Owner will use cost information from the revised USA and/or FERC Form 1 that is equivalent to the pre-Revision information in its application of the Formula Rate so that the Formula Rate's recovery of costs is unaffected by the Revision.

ATTACHMENT C

List of Owner Approvals

Set forth below are, to the best of Owner's knowledge, the Owner Approvals. The Owner Approvals do not include the AC Upgrade Approvals. Additional Governmental Approvals may be required as a result of (1) Applicable Laws that may come into effect after the Execution Date or (2) new and unexpected developments in the regulatory processes to be undertaken by Owner and its Affiliates in connection with the Northern Pass Transmission Line.

I. Construction Authorizations

1. U.S. Federal

Agency	Statute/Description
FERC	• Federal Power Act, Section 204 approval of Owner's ability to incur short term debt
FERC	• Federal Power Act, Section 205 approval of Transmission Service Agreement
FERC	• Federal Power Act, Section 205 approval of Facilities Agreement(s)
FERC	• Federal Power Act, Section 205 approval of Interconnection Agreements
U.S. Department of Energy ("DOE")	• Presidential Permit • Lead federal agency for development of an Environmental Impact Statement ("EIS") pursuant to the requirements of the National Environmental Policy Act ("NEPA") • DOE is responsible for developing the EIS that will be used by all U.S. federal agencies to fulfill the requirements of NEPA (the "NEPA/EIS development process") as those agencies process the U.S. federal permit applications for the Northern Pass Transmission Line
U.S. Forest Service ("USFS")	• Special Use Permit(s) for the Northern Pass Transmission Line to cross White Mountain National Forest (encompasses authorization to cross Appalachian Trail under the National Park Service's delegation of authority to USFS) • Modification to PSNH's existing Special Use Permits (WMNF) • Cooperating agency to NEPA/EIS development process
U.S. Army Corps of Engineers, New England District	• Permit issued under the Clean Water Act, codified at 33 U.S.C. § 1344 (§ 404 of the Clean Water Act) (Section 404 Permit) • Permit for applicable river crossings issued under Rivers and Harbors Act, 33 U.S.C. 403 § 10 • Cooperating agency to NEPA/EIS development process
U.S. Federal Aviation	• Approval of structures taller than 200 feet and for construction of

Agency	Statute/Description
Administration	facilities near airports
U.S. Environmental Protection Agency	• Clean Water Act, 33 U.S.C. § 1251 et seq., Construction General Permit (for discharge of construction-related stormwater)

2. Regional

Agency	Statute/Description
ISO-NE	• I.3.9 Project Technical Approval

3. State (New Hampshire) – Site Evaluation Committee

Agency	Statute/Description
New Hampshire Site Evaluation Committee ("SEC")	• Owner Siting Approvals • SEC Certificate (NH RSA Ch. 162-H)
New Hampshire Department of Environmental Services	• Section 401 Water Quality Certification (§ 401 of Clean Water Act) • Shoreland Protection Permit (if within 150 feet of ponds, lakes and other jurisdictional waters) (NH RSA Ch. 483-B) • Alteration of Terrain Permit (NH RSA Ch. 485-A) • Temporary and Permanent Groundwater Discharge Permit (NH RSA Ch. 485-A) • Wetlands Permits (NH RSA Ch. 482-A) • On Site Stump Disposal (No permit required per NH RSA § 149-M:4, XXII)
New Hampshire Public Utility Commission ("PUC")	• Approve Owner to commence business as a New Hampshire public utility (NH RSA § 374:22) • Approval of Owner's ability to issue short- and long-term securities (NH RSA §§ 369:1, 7) • Approval of Owner's condemnation of all land rights needed to create transmission right-of-way and to acquire other properties necessary to construct, operate and maintain the project facilities (post-siting approvals) (NH RSA § 371:1) • Approval of PSNH conveyance of Right-of-Way (ROW)/property to Owner (post-siting approvals, but pre-construction) (NH RSA § 374:30)
New Hampshire Department of Revenue and New Hampshire Division of Forests and Lands	• Notice of Intent to Cut (NH RSA § 79:10)
New Hampshire Department of Transportation	• Permit to Excavate in Roadways (NH RSA § 236:9)
New Hampshire Department of	• Authorization to cross public highways, rivers, and railroads

Agency	Statute/Description
Transportation/PUC	

II. All Other Owner Approvals

1. U.S. Federal

Agency	Statute/Description
FERC	Federal Power Act, Section 205 Approval of Transmission Operating Agreement
FERC	Federal Power Act, Section 205 Approval of ISO-NE Open Access Transmission Tariff changes (as applicable)
FERC	Federal Power Act, Section 205 approval of Scheduling and Dispatch Services Agreement between Owner and PSNH for PSNH's Electric System Control Center

2. Regional (ISO-NE)

Agency	Statute/Description
ISO-NE	Acceptance of AC Upgrades for interconnection and energization to the New England Transmission System
ISO-NE	Acceptance of Northern Pass Transmission Line for interconnection and energization to the New England Transmission System

3. State (New Hampshire)

Agency	Statute/Description
PUC	Approval of Owner's ability to issue long-term securities (NH RSA § 369:1)

EXECUTION COPY

ATTACHMENT D

List of Canadian Approvals

Set forth below are, to the best of Purchaser's knowledge, the Canadian Approvals. Additional Governmental Approvals may be required as a result of (1) Applicable Laws that may come into effect after the Execution Date or (2) new and unexpected developments in the regulatory processes to be undertaken by Purchaser and its Affiliates in connection with the Québec Line.

- Permit or certificate, as the case may be, from the National Energy Board to construct or operate an international power line pursuant to the National Energy Board Act (R.S.C., 1985,c. N-7)

- Authorization of the Régie de l'énergie (Québec Energy Board) to acquire or construct immovables or assets for transmission purposes pursuant to An Act respecting the Régie de l'énergie (R.S.Q., chapter R-6.01)

- Certificate of authorization issued by the Government of Québec for the realization of the construction or relocation of an electric power transmission line of 315 kV or more over a distance of more than 2 km and the construction or relocation of a control and transformer station of 315 kV or more pursuant to the Environment Quality Act (R.S.Q., chapter Q-2)

- Authorization of the "Commission de protection du territoire agricole du Québec" to use a lot for any purpose other than agriculture pursuant to An Act respecting the preservation of agricultural land and agricultural activities (R.S.Q., chapter P-41.1)

- Assessment of conformity consistent with the objectives of the land use and development plan of each regional county municipality or municipality where an intervention is planned by Hydro-Québec pursuant to An Act respecting land use planning and development (R.S.Q., chapter A-19.1) (the "Land Use Planning Act") and the Order in council 554-81

- Certificate pursuant to the Regulation respecting the application of the Environment Quality Act (c. Q-2, r. 1.001) issued by the clerk or the secretary-treasurer of each local municipality affected by the project or, in the case of an unorganized territory, of each regional county municipality affected by the project attesting that the project does not contravene any municipal bylaw

- Expropriation Order in council, if required, to acquire by expropriation any immovable, servitude or construction required for the transmission of power pursuant to Hydro-Québec Act (R.S.Q., chapter H-5) and the Expropriation Act (R.S.Q., chapter E-24)

- Authorization from the International Boundary Commission to cross the Canada-U.S. border pursuant to Article 5 of the International Boundary Commission Act

- Approval, if required, by ISO-NE of Québec Line siting

EXECUTION COPY

ATTACHMENT E-1

Form of Purchaser Guaranty

Please see the attached.

Hydro-Québec
75, boulevard René-Lévesque ouest
5ième étage
Montréal, Québec, Canada
H2Z 1A4

GUARANTY AGREEMENT

This Guaranty Agreement ("Guaranty"), dated as of October 4, 2010, is made and entered into by **Hydro-Québec**, a body politic and corporate, duly incorporated and regulated by Hydro-Québec Act (R.S.Q., chapter H-5) and having its head office and principal place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as the "Guarantor"), in favor of **Northern Pass Transmission LLC**, a limited liability company organized and existing under the laws of the State of New Hampshire and having its principal place of business at Energy Park, 780 North Commercial Street, Manchester, NH 03101, United States of America (hereinafter referred to as the "Beneficiary").

WHEREAS the Beneficiary and **H.Q. Hydro Renewable Energy, Inc.**, a corporation created under the laws of the State of Delaware and having its place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as "HQSub"), an indirectly owned subsidiary of the Guarantor, have executed a Transmission Service Agreement, dated as of October 4, 2010 (hereinafter referred to as the "Agreement") (capitalized terms used but not defined in this Guaranty to have the meaning accorded such terms in the Agreement);

WHEREAS the Guarantor will directly or indirectly benefit from the Agreement; and

WHEREAS the Beneficiary has required that the Guarantor guarantee to the Beneficiary payment of all obligations of HQSub under the Agreement, and the Guarantor has agreed to guarantee such obligations, subject to a maximum dollar limitation and the other terms and conditions provided in this Guaranty;

NOW THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby agrees with the Beneficiary as follows:

Section 1. <u>Guaranty</u>.

(a) <u>Guaranteed Obligations</u>. The Guarantor absolutely, irrevocably, and unconditionally guarantees to the Beneficiary, its successors and endorsees and assignees, as primary obligor and not merely as a surety, (i) the payment of all present and future amounts owed by HQSub to the Beneficiary under the Agreement (excluding HQSub's obligation to pay Net Decommissioning Costs, but including payment of HQSub's indemnification obligations, other than as may relate to Net Decommissioning Costs), not later than the date that is thirty (30) days after a written demand by the Beneficiary upon the Guarantor stating that HQSub has failed to pay any such amount when due under the Agreement after demand therefor in accordance with the Agreement; <u>provided</u>, that the aggregate liability of the Guarantor under this Section 1(a) shall not exceed Fifty-Five Million U.S. Dollars (U.S. $55,000,000) (the "Stated Cap"), plus (ii) payment of all Decommissioning Liquidated Damages, as provided in Section 1(b) of this Guaranty, plus (iii) payment of all third-party, out-of-pocket costs or expenses reasonably incurred by the Beneficiary to enforce its rights against the Guarantor under this Guaranty

including reasonable attorneys' fees, court costs and similar costs (such amounts and such costs and expenses hereinafter collectively called "Guaranteed Obligations"); provided, further, that it shall be a condition precedent to the Guarantor's obligations under this Guaranty that the Construction Phase shall have commenced under the Agreement; provided, further, that, subject to Section 8 of this Guaranty, this Guaranty shall terminate when and as provided in Section 9 of this Guaranty.

(b) Net Decommissioning Costs.

(i) The Guarantor's obligations under Section 1(a)(ii) of this Guaranty shall be limited to the payment of (A) the estimated Net Decommissioning Costs, as set forth in the Decommissioning Plan approved by the Management Committee (or determined pursuant to the dispute resolution provisions in the Agreement in the event of an Impasse with respect thereto) (which estimated Net Decommissioning Costs, solely for the purpose of calculating the Decommissioning Liquidated Damages, shall be expressed in dollars as of the date on which the Agreement is terminated as if the Decommissioning were to commence as of such date), less (B) the balance, if any, in the Decommissioning Fund as of the date of the Beneficiary's written demand under Section 1(b)(ii) of this Guaranty (net of any portion of such balance that is required to be restored to HQSub pursuant to the Bankruptcy Code or any other Insolvency Laws) (such amount, the "Decommissioning Liquidated Damages"); provided, that, if a Subsequent Use occurs, then the Guarantor's obligations under Section 1(a)(ii) of this Guaranty and this Section 1(b) shall be subject to the provisions of Section 9.3.4 of the Agreement.

(ii) The Decommissioning Liquidated Damages shall be payable by the Guarantor to the Beneficiary within thirty (30) days after receipt by the Guarantor from the Beneficiary of (A) a written demand by the Beneficiary upon the Guarantor stating that a Purchaser Default under Section 15.1(a) of the Agreement has occurred and is continuing with respect to HQSub's obligation to pay Net Decommissioning Costs pursuant to Section 9.3.3 of the Agreement (including the Levelized Monthly Decommissioning Payment and/or the Preliminary Monthly Decommissioning Payment included in the Formula Rate pursuant to Section 9.3.3(a) of the Agreement and/or the Decommissioning Estimate), (B) a certificate of the Beneficiary certifying that the Beneficiary has received all Governmental Approvals required under Applicable Law and all other consents and approvals as otherwise may be required, in each case, to commence such Decommissioning in accordance with the Decommissioning Plan, and that there are no other conditions to the undertaking of such Decommissioning, other than the payment of Decommissioning Liquidated Damages as provided herein, and (C) an irrevocable written commitment to commence to Decommission the Northern Pass Transmission Line not later than the date that is ninety (90) days after the Beneficiary's receipt of the Decommissioning Liquidated Damages (such period to be extended as and to the extent required for any period of Force Majeure), and to complete such Decommissioning in accordance with the Decommissioning Plan, such Governmental Approvals, and such other consents and approvals.

(iii) For the avoidance of doubt, (A) the Guarantor shall not have any obligation to pay any amount relating to Decommissioning Costs, including under Section 9.3.5(d) of the Agreement, other than Decommissioning Liquidated Damages as provided herein, and (B) upon the payment of such Decommissioning Liquidated Damages, (1) neither HQ Sub nor the Guarantor shall have any obligation to pay any other amount relating to

Decommissioning Costs, including under Section 9.3.5(d) of the Agreement, and (2) neither HQSub nor the Guarantor shall be entitled to any reimbursement, refund or reduction if the actual Net Decommissioning Costs are less than the Decommissioning Liquidated Damages.

(c) Guaranty of Payment and Not Collection. This Guaranty is a guaranty of payment and not merely of collection.

(d) Information. At the Guarantor's request, the Beneficiary shall provide the Guarantor with any useful information respecting the content and the terms and conditions of the Guaranteed Obligations and a statement of account with details of billings and payments; provided, that such a request by the Guarantor shall not delay or prevent the Guarantor from paying under this Guaranty.

Section 2. Nature of Guaranty. The Guarantor's obligations hereunder shall be subject to all the contractual protections, limitations, waivers, exclusions and rights that HQSub has under the Agreement, and the Guarantor shall be entitled to the benefits of any modification of, amendment to, waiver of or consent to departure from, the Agreement to the extent, if any, HQSub would have been entitled to such benefits. Nonetheless, this Guaranty shall not be deemed discharged, impaired or affected by the existence, validity, enforceability, perfection, or extent of any collateral for any obligations under the Agreement of HQSub.

Section 3. Consents, Waivers and Renewals. The Guarantor agrees that the Beneficiary may at any time and from time to time, either before or after maturity thereof, without notice to or further consent of the Guarantor, extend the time of payment of any of HQSub's obligations under the Agreement, or accept, exchange or surrender any collateral therefor, or renew the Agreement, and may also make any agreement with HQSub or with any other party to, or Person liable for any of the obligations contemplated in, the Agreement, or interested therein, for the extension, renewal, payment, compromise, discharge or release thereof, in whole or in part, or for any modification of the terms thereof or of any agreement between the Beneficiary and HQSub or any such other party or Person, without in any way impairing or affecting this Guaranty. The obligations of the Guarantor hereunder are independent of the obligations of HQSub, and the Guarantor agrees that the Beneficiary may resort to the Guarantor for payment of the Guaranteed Obligations, whether or not the Beneficiary shall have resorted to any collateral security, or shall have proceeded against any other obligor principally or secondarily obligated with respect to any of the Guaranteed Obligations, and whether or not HQSub is joined in an action or proceeding against the Guarantor or a separate action or actions are brought against HQSub.

Section 4. Subrogation. In any case, including HQSub's insolvency, the Guarantor will not exercise any rights that it may acquire by way of subrogation, and hereby waives, to the fullest extent permitted by Applicable Law, any right to enforce any remedy that the Beneficiary now has or may hereafter have against HQSub in respect of the Guaranteed Obligations. Notwithstanding the foregoing, upon full, final and indefeasible payment of all Guaranteed Obligations, the Guarantor shall be subrogated to the rights of the Beneficiary against HQSub and the Beneficiary agrees to take, at the Guarantor's expense, such steps as the Guarantor may reasonably request to implement such subrogation; provided, that, if a bankruptcy court in a bankruptcy proceeding of HQSub issues a stay or injunction prohibiting or preventing the

Guarantor from reissuing this Guaranty, as contemplated by Section 17.1.1 of the Agreement, based in whole or in part on the effects on the estate of HQSub of any increase in the Stated Cap after the entry of an order of relief with respect to HQSub from the amount of the Stated Cap in the Purchaser Guaranty prior to such reissuance, and/or on the effects on the estate of HQSub of the Guarantor's rights of subrogation resulting from such increase, then, in either such case, the Guarantor's waiver set forth in this Section 4 shall be absolute and permanent with respect to the portion of the Guaranteed Obligations equal to the amount of such increase; provided, further, that nothing in this Section 4 or in Section 8 of this Guaranty shall be construed to prevent the Guarantor from opposing or seeking to terminate such stay or injunction or any request of a third party for such a stay or injunction, in such bankruptcy proceeding.

Section 5. Waiver; Cumulative Rights. No waiver of any provision of this Guaranty shall be binding unless in a writing signed by the Beneficiary and specifically referring to this Guaranty. No failure on the part of the Beneficiary to exercise, and no delay in exercising any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any waiver nor any single or partial exercise by the Beneficiary of any right, remedy or power hereunder preclude any other future exercise of any right, remedy or power. Each and every right, remedy and power hereby granted to the Beneficiary or allowed to it by Applicable Law or other agreement shall be cumulative and not exclusive of any other, and may be exercised by the Beneficiary from time to time.

Section 6. Waivers.

(a) Waiver of Notice. The Guarantor waives notice of the acceptance of this Guaranty, notice of dishonor, presentment and demand, except as set forth in Section 1 of this Guaranty, notice of exercise of any right and all other notices whatsoever.

(b) Waiver of Immunities. The Guarantor agrees and acknowledges that this Guaranty and the Agreement constitute a commercial transaction. To the extent the Guarantor may be entitled, in any jurisdiction, to claim for itself, or any of its assets, revenues or properties, sovereign or other immunity, as the case may be, from service of process, suit, the jurisdiction of any court or arbitral tribunal, attachment (whether in aid of execution or otherwise) or enforcement of a judgment (interlocutory or final) or award or any other legal process in a matter arising out of or relating to this Guaranty, the Guarantor, to the fullest extent permitted by Applicable Law, agrees not to claim or assert, and hereby waives, such immunity. Without limiting the generality of the foregoing, the Guarantor agrees that the waivers set forth in this paragraph shall have the fullest scope permitted under the United States Foreign Sovereign Immunities Act of 1976, 28 U.S.C. § 1602 *et seq*., the Hydro-Québec Act (R.S.Q., chapter H-5) and under any other Applicable Law related to sovereign immunity.

(c) Absolute Guaranty. To the fullest extent permitted by Applicable Law, and except as limited by the express terms hereof, the liability of the Guarantor under this Guaranty shall be absolute, unconditional and irrevocable irrespective of, and the Guarantor waives any right or defense arising out of: (i) the lack of power or authority of the Guarantor to execute and deliver this Guaranty or of HQSub to execute and deliver the Agreement; (ii) the failure of HQSub to exist as a legal entity or the consolidation or merger of HQSub with or into any other corporation or other entity, or the sale, lease or other disposition by HQSub of all or substantially

all of its assets to any other business entity; (iii) any disposal, transfer, assignment or other disposition or all or any part of the direct or indirect interest of the Guarantor in HQSub; (iv) the bankruptcy, insolvency, dissolution, administration, reorganization or liquidation of HQSub, the admission in writing by HQSub of its inability to pay its debts as they mature, or its making of a general assignment for the benefit of, or entering into a composition or arrangement with creditors or similar proceeding (whether such right or defence is available to the Guarantor, HQSub, as debtor, or HQSub's trustee or receiver); (v) any failure to give to the Guarantor notice of default in the making of any payment due and payable under this Guaranty or the Agreement, or notice of any failure on the part of HQSub to do any act or thing or to observe or perform any covenant, condition or agreement by it to be observed or performed under the Agreement, except for the obligations to make demand for payment as set forth under Section 1 of this Guaranty; (vi) the absence, impairment or loss of any right of reimbursement, contribution or subrogation or any other right or remedy of the Guarantor against HQSub; (vii) subject to Section 2 of this Guaranty, any amendment, modification or extension of the Agreement; (viii) any assertion or claim that the automatic or other stay provided by Section 362 of the Bankruptcy Code or the equivalent legislation of any other country arising upon the voluntary or involuntary bankruptcy proceeding of HQSub shall operate or be interpreted to stay, interdict, condition, reduce or inhibit the ability of the Beneficiary to enforce any rights that the Beneficiary may have against the Guarantor; and (ix) any other circumstances whatsoever (with or without knowledge of the Beneficiary or the Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge or defense of the Guarantor under this Guaranty, in bankruptcy or in any other instance, including all defenses of a guarantor or surety generally, other than full, final and indefeasible payment of the Guaranteed Obligations by the Guarantor and/or HQSub.

Section 7. <u>Representations and Warranties</u>.

The Guarantor represents and warrants that:

a) It is a corporation duly organized, validly existing and in good standing under the laws of the jurisdiction of its incorporation and has full corporate power to execute, deliver and perform this Guaranty;

b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary corporate action and do not contravene any provision of any Applicable Law applicable to or binding on the Guarantor or any of its properties or the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets and that the individual or individuals executing this Guaranty for and on behalf of the Guarantor have been duly authorized to do so;

c) This Guaranty constitutes a legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity; and

d) There is no pending or, to the best of the Guarantor's knowledge, threatened action or proceeding affecting the Guarantor before any Governmental Authority that might reasonably be expected to materially and adversely affect the ability of the Guarantor to perform its obligations under this Guaranty.

Section 8. Setoff and Counterclaims; Bankruptcy. Notwithstanding anything in this Guaranty to the contrary, the Guarantor shall be entitled to assert all rights and defenses that HQSub may be entitled to under the Agreement, including any setoff or counterclaims that HQSub is or may be entitled to under the Agreement, except that the Guarantor shall not be entitled to any rights or defenses arising out of the matters described in clauses (i) through (viii) of Section 6(c) of this Guaranty. Notwithstanding anything in Section 9 of this Guaranty to the contrary, the obligations of the Guarantor under this Guaranty automatically shall be reinstated if and to the extent that, for any reason, any payment by or on behalf of HQSub in respect of the Guaranteed Obligations is rescinded or must be otherwise restored by any holder of any of the Guaranteed Obligations, whether as a result of any proceedings in bankruptcy or reorganization or otherwise. The Guarantor hereby agrees not to seek an injunction or otherwise seek to stay its liability under this Guaranty in any voluntary or involuntary bankruptcy proceeding of HQSub and, in the event such injunction or stay issues at the instance of a third party, to take such steps as may be necessary or appropriate to seek to terminate or dissolve any such injunction or stay.

Section 9. Termination.

(a) Continuing Guaranty. The Guarantor acknowledges that the Beneficiary has entered into the Agreement in reliance on this Guaranty being a continuing and irrevocable agreement and the Guarantor agrees that this Guaranty may not be revoked in whole or in part, except that this Guaranty and the Guarantor's liability hereunder may be terminated as provided in this Section 9.

(b) Expiration. This Guaranty is a continuing guarantee effective upon the commencement of the Construction Phase. The Guarantor's obligations with respect to the Guaranteed Obligations under Section 1(a)(i) and Section 1(a)(iii) of this Guaranty shall expire upon the full, final and indefeasible payment of such Guaranteed Obligations. The Guarantor's obligations with respect to the Guaranteed Obligations under Section 1(a)(ii) of this Guaranty shall expire upon the earlier of full, final and indefeasible payment of such Guaranteed Obligations or the fortieth (40th) anniversary of the Commercial Operation Date, except that the Guarantor shall remain liable for any Guaranteed Obligations under Section 1(a)(ii) of this Guaranty relating to the period prior to such fortieth (40th) anniversary that are then due and remain unpaid and for which the Beneficiary shall have given written notice to the Guarantor pursuant to Section 1(b)(ii) of this Guaranty prior to such fortieth (40th) anniversary.

(c) Reissuance. Subject to Section 17.1.1(e) of the Agreement, upon the execution by the Guarantor and delivery to the Beneficiary, pursuant to Section 17.1.1 of the Agreement, of a new guaranty in replacement of this Guaranty, in the form of the Purchaser Guaranty attached as Attachment E-1 to the Agreement, with a revised Stated Cap redetermined in accordance with Section 17.1.1 of the Agreement, (i) this Guaranty shall terminate and (ii) at the request of the Guarantor, the Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of this Guaranty, in such form as the Guarantor may reasonably request, with respect to such termination. This Section 9(c) shall not apply unless and until the Beneficiary shall have received a duly executed replacement guaranty in compliance with the terms and conditions for a reissued Purchaser Guaranty set forth in Section 17.1.1 of the Agreement.

(d) Transfer. Upon any Transfer by HQSub that is permitted by Section 23.1 of the Agreement, including (i) the approval of such Transfer by the Beneficiary, (ii) the assumption in writing by the Transferee of HQSub's obligations associated with the Transferred portion of the Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (iii) delivery to the Beneficiary of any replacement security or other financial assurances to be provided by on or behalf of the Transferee in connection with such Transfer in accordance with the Agreement, then, provided, that a Purchaser Default shall not have occurred and be continuing, (x) the obligations of the Guarantor hereunder shall terminate to the extent of the Transferred portion of the Agreement and the Guarantor shall be fully, finally, and unconditionally released from all liability with respect thereto associated with the Transferred portion of the Agreement (it being understood that the Stated Cap shall be reduced in proportion to the Transferred portion of the Agreement), and (y) at the request of the Guarantor, the Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of the Guaranteed Obligations, in such form as the Guarantor may reasonably request, with respect to the Transferred portion of the Agreement. For the avoidance of doubt, this Section 9(d) does not apply to any Transfer permitted by Section 23.2 or Section 23.3 of the Agreement.

Section 10. Assignment. The Guarantor shall not be entitled to assign its rights, interest or obligations hereunder to any other Person without the prior written consent of the Beneficiary. The Beneficiary shall be entitled to assign its rights, interest or obligations hereunder solely in connection with an assignment of the Agreement permitted pursuant to the terms of the Agreement. Upon a collateral assignment of this Guaranty in connection with a collateral assignment of the Agreement permitted under the Agreement, the Guarantor shall cooperate with the Beneficiary and shall execute and deliver such consents, acknowledgements, direct agreements or similar documents as may be customary for financings of a similar nature and reasonably requested by any Financing Party.

Section 11. Notices. All notices or other communications in respect of this Guaranty shall be in writing, and delivered by hand or by registered mail (return receipt requested), overnight courier service or given by facsimile (except for a demand for payment) and addressed or directed as follows:

If to the Guarantor:

HYDRO-QUÉBEC
Attention: Vice-President Financing, Treasury and Pension Fund
75, René-Lévesque Boulevard West
5th Floor
Montréal (Québec) Canada
H2Z 1A4
Facsimile: (514)289-5409

If to the Beneficiary:

NORTHERN PASS TRANSMISSION LLC
c/o NORTHEAST UTILITIES
Attention: Randy Shoop, Vice-President and Treasurer
56 Prospect Street
Hartford, Connecticut 06103

United States of America
Facsimile: (860)728-4585

or such address as the Guarantor or the Beneficiary may give notice to the other party, from time to time.

Section 12. Successors; No Third-Party Beneficiaries. This Guaranty shall be binding upon the Guarantor, its successors and permitted assigns. This Guaranty shall inure to the benefit of the Beneficiary and its successors and permitted assigns. This Guaranty is not intended to create any third-party beneficiaries.

Section 13. Governing Law. This Guaranty shall be governed by and construed in accordance with the laws of the State of New York (without regard to principles of conflict of laws that would direct for application of the laws of another jurisdiction).

Section 14. Submission to Jurisdiction. Each of the Guarantor and the Beneficiary hereto consents to submit itself to the exclusive jurisdiction of any state or federal court of competent jurisdiction located in the State of New York, United States of America, with respect to any dispute that arises under this Guaranty or in connection with the transactions contemplated hereby, and irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of or relating to this Guaranty or the transactions contemplated hereby in (a) the courts of the State of New York in New York County, or (b) the United States District Court for the Southern District of New York, and hereby further irrevocably and unconditionally waives and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum.

Section 15. Waiver of Jury Trial. EACH PARTY HEREBY KNOWINGLY, VOLUNTARILY, AND INTENTIONALLY WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS GUARANTY OR THE AGREEMENT.

Section 16. Entire Agreement. This Guaranty constitutes the entire agreement of the Guarantor and the Beneficiary pertaining to the subject matter hereof and supersedes all prior written or oral agreements and understandings between the Guarantor and the Beneficiary with respect to the subject matter hereof.

Section 17. Amendments. No amendments or modifications of or to any provision of this Guaranty shall be binding until in writing and executed by the Guarantor and the Beneficiary. For the avoidance of doubt, this Guaranty may be reissued as provided in Section 9(c) of this Guaranty without a writing executed by the Beneficiary and such reissuance shall not require acceptance by the Beneficiary.

Section 18. Severability. If any one or more of the provisions of this Guaranty should be determined to be illegal or unenforceable, all other provisions shall remain effective.

EXECUTION COPY

Section 19. **Interpretation.** The word "including" when used in this Guaranty shall be deemed to be followed by "without limitation" or "but not limited to, " whether or not it is in fact followed by such words or words of like import.

Section 20. **Counterparts.** This Guaranty may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Guarantor and the Beneficiary acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

HYDRO-QUÉBEC

By: _____
Name:
Title: Jean-Hugues Lafleur
Vice President - Financing
Treasury and Pension Fund
Date: Oct. 4, 2010

By: _____
Name: STEPHANE PEPIN
Title: DIRECTOR
Date:

Accepted:

NORTHERN PASS TRANSMISSION LLC

By: _____
Name:
Title:
Date:

EXECUTION COPY

Section 19. **Interpretation.** The word "including" when used in this Guaranty shall be deemed to be followed by "without limitation" or "but not limited to, " whether or not it is in fact followed by such words or words of like import.

Section 20. **Counterparts.** This Guaranty may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Guarantor and the Beneficiary acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

HYDRO-QUÉBEC

By: _____
Name:
Title:
Date:

By: _____
Name:
Title:
Date:

Accepted:

NORTHERN PASS TRANSMISSION LLC

By: _____
Name: James A. Muntz
Title: President - Northern Pass Transmission LLC
Date: October 4, 2010

ATTACHMENT E-2

Form of Owner Guaranties

Please see the attached.

EXECUTION COPY

NSTAR

GUARANTY AGREEMENT

This Guaranty Agreement ("Guaranty"), dated as of October 4, 2010, is made and entered into by **NSTAR**, a public utility holding company organized and existing as a voluntary association under the laws of the Commonwealth of Massachusetts and having its head office and principal place of business at 800 Boylston Street, 17th Floor, Boston, MA 02199, United States of America (hereinafter referred to as the "Guarantor"), in favor of **H.Q. Hydro Renewable Energy, Inc.**, a corporation organized and existing under the laws of the State of Delaware and having its principal place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as the "Beneficiary").

WHEREAS the Beneficiary and **Northern Pass Transmission LLC,** a limited liability company organized and existing under the laws of the State of New Hampshire and having its place of business at Energy Park, 780 North Commercial Street, Manchester, NH 03101, United States of America (hereinafter referred to as "NPT"), have executed a Transmission Service Agreement, dated as of October 4, 2010 (hereinafter referred to as the "Agreement") (capitalized terms used but not defined in this Guaranty to have the meaning accorded such terms in the Agreement);

WHEREAS the Guarantor indirectly owns, through a wholly-owned subsidiary, a portion of the beneficial ownership interests in NPT and will directly or indirectly benefit from the Agreement; and

WHEREAS the Beneficiary has required that the Guarantor guarantee to the Beneficiary payment of all obligations of NPT under the Agreement, and the Guarantor has agreed to guarantee such obligations, subject to a maximum dollar limitation and the other terms and conditions provided in this Guaranty;

NOW THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby agrees with the Beneficiary as follows:

Section 1. Guaranty.

(a) Guaranteed Obligations. The Guarantor absolutely, irrevocably, and unconditionally guarantees to the Beneficiary, its successors and endorsees and assignees, as primary obligor and not merely as a surety, (i) the payment of all present and future amounts owed by NPT to the Beneficiary under the Agreement (including payment of NPT's indemnification obligations), not later than the date that is thirty (30) days after a written demand by the Beneficiary upon the Guarantor stating that NPT has failed to pay any such amount when due under the Agreement after demand therefor in accordance with the Agreement; provided, that the aggregate liability of the Guarantor under this Section 1(a) shall not exceed $6,250,000.00, plus (ii) payment of all third-party, out-of-pocket costs or expenses reasonably incurred by the Beneficiary to enforce its rights against the Guarantor under this Guaranty

including reasonable attorneys' fees, court costs and similar costs (such amounts and such costs and expenses hereinafter collectively called "Guaranteed Obligations"); provided, further, that it shall be a condition precedent to the Guarantor's obligations under this Guaranty that the Operation Phase shall have commenced under the Agreement; provided, further, that, subject to Section 8 of this Guaranty, this Guaranty shall terminate when and as provided in Section 9 of this Guaranty.

(b) Guaranty of Payment and Not Collection. This Guaranty is a guaranty of payment and not merely of collection.

(c) Information. At the Guarantor's request, the Beneficiary shall provide the Guarantor with any useful information respecting the content and the terms and conditions of the Guaranteed Obligations and a statement of account with details of billings and payments; provided, that such a request by the Guarantor shall not delay or prevent the Guarantor from paying under this Guaranty.

Section 2. Nature of Guaranty. The Guarantor's obligations hereunder shall be subject to all the contractual protections, limitations, waivers, exclusions and rights that NPT has under the Agreement, and the Guarantor shall be entitled to the benefits of any modification of, amendment to, waiver of or consent to departure from, the Agreement to the extent, if any, NPT would have been entitled to such benefits. Nonetheless, this Guaranty shall not be deemed discharged, impaired or affected by the existence, validity, enforceability, perfection, or extent of any collateral for any obligations under the Agreement of NPT.

Section 3. Consents, Waivers and Renewals. The Guarantor agrees that the Beneficiary may at any time and from time to time, either before or after maturity thereof, without notice to or further consent of the Guarantor, extend the time of payment of any of NPT's obligations under the Agreement, or accept, exchange or surrender any collateral therefor, or renew the Agreement, and may also make any agreement with NPT or with any other party to, or Person liable for any of the obligations contemplated in, the Agreement, or interested therein, for the extension, renewal, payment, compromise, discharge or release thereof, in whole or in part, or for any modification of the terms thereof or of any agreement between the Beneficiary and NPT or any such other party or Person, without in any way impairing or affecting this Guaranty. The obligations of the Guarantor hereunder are independent of the obligations of NPT, and the Guarantor agrees that the Beneficiary may resort to the Guarantor for payment of the Guaranteed Obligations, whether or not the Beneficiary shall have resorted to any collateral security, or shall have proceeded against any other obligor principally or secondarily obligated with respect to any of the Guaranteed Obligations, and whether or not NPT is joined in an action or proceeding against the Guarantor or a separate action or actions are brought against NPT.

Section 4. Subrogation. In any case, including NPT's insolvency, the Guarantor will not exercise any rights that it may acquire by way of subrogation, and hereby waives, to the fullest extent permitted by Applicable Law, any right to enforce any remedy that the Beneficiary now has or may hereafter have against NPT in respect of the Guaranteed Obligations. Notwithstanding the foregoing, upon full, final and indefeasible payment of all Guaranteed Obligations, the Guarantor shall be subrogated to the rights of the Beneficiary against NPT and the Beneficiary agrees to take, at the Guarantor's expense, such steps as the Guarantor may

reasonably request to implement such subrogation; provided, that, if a bankruptcy court in a bankruptcy proceeding of NPT issues a stay or injunction prohibiting or preventing the Guarantor from amending this Guaranty, as contemplated by Section 17.1.2 of the Agreement, based in whole or in part on the effects on the estate of NPT of any increase in the aggregate liability of the Guarantor under Section 1(a) of this Guaranty after the entry of an order of relief with respect to NPT from the amount of the aggregate liability of the Guarantor under Section 1(a) of this Guaranty in the Owner Guaranty prior to such amendment, and/or on the effects on the estate of NPT of the Guarantor's rights of subrogation resulting from such increase, then, in either such case, the Guarantor's waiver set forth in this Section 4 shall be absolute and permanent with respect to the portion of the Guaranteed Obligations equal to the amount of such increase; provided, further, that nothing in this Section 4 or in Section 8 of this Guaranty shall be construed to prevent the Guarantor from opposing or seeking to terminate such stay or injunction or any request of a third party for such a stay or injunction, in such bankruptcy proceeding.

Section 5. Waiver; Cumulative Rights. No waiver of any provision of this Guaranty shall be binding unless in a writing signed by the Beneficiary and specifically referring to this Guaranty. No failure on the part of the Beneficiary to exercise, and no delay in exercising any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any waiver nor any single or partial exercise by the Beneficiary of any right, remedy or power hereunder preclude any other future exercise of any right, remedy or power. Each and every right, remedy and power hereby granted to the Beneficiary or allowed to it by Applicable Law or other agreement shall be cumulative and not exclusive of any other, and may be exercised by the Beneficiary from time to time.

Section 6. Waivers.

(a) Waiver of Notice. The Guarantor waives notice of the acceptance of this Guaranty, notice of dishonor, presentment and demand, except as set forth in Section 1 of this Guaranty, notice of exercise of any right and all other notices whatsoever.

(b) Absolute Guaranty. To the fullest extent permitted by Applicable Law, and except as limited by the express terms hereof, the liability of the Guarantor under this Guaranty shall be absolute, unconditional and irrevocable irrespective of, and the Guarantor waives any right or defense arising out of: (i) the lack of power or authority of the Guarantor to execute and deliver this Guaranty or of NPT to execute and deliver the Agreement; (ii) the failure of NPT to exist as a legal entity or the consolidation or merger of NPT with or into any other corporation or other entity, or the sale, lease or other disposition by NPT of all or substantially all of its assets to any other business entity; (iii) any disposal, transfer, assignment or other disposition or all or any part of the direct or indirect interest of the Guarantor in NPT; (iv) the bankruptcy, insolvency, dissolution, administration, reorganization, or liquidation of NPT, the admission in writing by NPT of its inability to pay its debts as they mature, or its making of a general assignment for the benefit of, or entering into a composition or arrangement with creditors or similar proceeding (whether such right or defence is available to the Guarantor, NPT, as debtor, or NPT's trustee or receiver); (v) any failure to give to the Guarantor notice of default in the making of any payment due and payable under this Guaranty or the Agreement, or notice of any failure on the part of NPT to do any act or thing or to observe or perform any covenant, condition or agreement by it to be observed or performed under the Agreement, except for the obligations to make demand for

payment as set forth under Section 1 of this Guaranty; (vi) the absence, impairment or loss of any right of reimbursement, contribution or subrogation or any other right or remedy of the Guarantor against NPT; (vii) subject to Section 2 of this Guaranty, any amendment, modification or extension of the Agreement; (viii) any assertion or claim that the automatic or other stay provided by Section 362 of the Bankruptcy Code or the equivalent legislation of any other country arising upon the voluntary or involuntary bankruptcy proceeding of NPT shall operate or be interpreted to stay, interdict, condition, reduce or inhibit the ability of the Beneficiary to enforce any rights that the Beneficiary may have against the Guarantor; and (ix) any other circumstances whatsoever (with or without knowledge of the Beneficiary or the Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge or defense of the Guarantor under this Guaranty, in bankruptcy or in any other instance, including all defenses of a guarantor or surety generally, other than full, final and indefeasible payment of the Guaranteed Obligations by the Guarantor and/or NPT.

Section 7. Representations and Warranties.

The Guarantor represents and warrants that:

a) It is a public utility holding company duly organized as a voluntary association, validly existing and in good standing under the laws of the jurisdiction of its formation and has full voluntary association power to execute, deliver and perform this Guaranty;

b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary voluntary association action and do not contravene any provision of any Applicable Law applicable to or binding on the Guarantor or any of its properties or the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets and that the individual or individuals executing this Guaranty for and on behalf of the Guarantor have been duly authorized to do so;

c) This Guaranty constitutes a legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity; and

d) There is no pending or, to the best of the Guarantor's knowledge, threatened action or proceeding affecting the Guarantor before any Governmental Authority that might reasonably be expected to materially and adversely affect the ability of the Guarantor to perform its obligations under this Guaranty.

Section 8. Setoff and Counterclaims; Bankruptcy. Notwithstanding anything in this Guaranty to the contrary, the Guarantor shall be entitled to assert all rights and defenses that NPT may be entitled to under the Agreement, including any setoff or counterclaims that NPT is or may be entitled to under the Agreement, except that the Guarantor shall not be entitled to any rights or defenses arising out of the matters described in clauses (i) through (viii) of Section 6(b) of this Guaranty. Notwithstanding anything in Section 9 of this Guaranty to the contrary, the obligations of the Guarantor under this Guaranty automatically shall be reinstated if and to the extent that, for any reason, any payment by or on behalf of NPT in respect of the Guaranteed Obligations is rescinded or must be otherwise restored by any holder of any of the Guaranteed

Obligations, whether as a result of any proceedings in bankruptcy or reorganization or otherwise. The Guarantor hereby agrees not to seek an injunction or otherwise seek to stay its liability under this Guaranty in any voluntary or involuntary bankruptcy proceeding of NPT and, in the event such injunction or stay issues at the instance of a third party, to take such steps as may be necessary or appropriate to seek to terminate or dissolve any such injunction or stay.

Section 9. Termination.

(a) Continuing Guaranty. The Guarantor acknowledges that the Beneficiary has entered into the Agreement in reliance on this Guaranty being a continuing and irrevocable agreement and the Guarantor agrees that this Guaranty may not be revoked in whole or in part, except that this Guaranty and the Guarantor's liability hereunder may be terminated as provided in this Section 9.

(b) Expiration. This Guaranty is a continuing guarantee effective upon the commencement of the Operation Phase. The Guarantor's obligations with respect to the Guaranteed Obligations shall expire upon the full, final and indefeasible payment of such Guaranteed Obligations.

(c) Transfer. Upon any Transfer by NPT that is permitted by Section 23.1 of the Agreement, including (i) the approval of such Transfer by the Beneficiary, (ii) the assumption in writing by the Transferee of NPT's obligations associated with the Transferred portion of the Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (iii) delivery to the Beneficiary of any replacement security or other financial assurances to be provided by on or behalf of the Transferee in connection with such Transfer in accordance with the Agreement, then, provided, that an Owner Default shall not have occurred and be continuing, (x) the obligations of the Guarantor hereunder shall terminate to the extent of the Transferred portion of the Agreement and the Guarantor shall be fully, finally, and unconditionally released from all liability with respect thereto associated with the Transferred portion of the Agreement (it being understood that the aggregate liability of the Guarantor under Section 1(a) of this Guaranty shall be reduced in proportion to the Transferred portion of the Agreement), and (y) at the request of the Guarantor, the Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of the Guaranteed Obligations, in such form as the Guarantor may reasonably request, with respect to the Transferred portion of the Agreement. For the avoidance of doubt, this Section 9(c) does not apply to any Transfer permitted by Section 23.2 or Section 23.3 of the Agreement.

Section 10. Assignment. The Guarantor shall not be entitled to assign its rights, interest or obligations hereunder to any other Person without the prior written consent of the Beneficiary. The Beneficiary shall be entitled to assign its rights, interest or obligations hereunder solely in connection with an assignment of the Agreement permitted pursuant to the terms of the Agreement.

Section 11. Notices. All notices or other communications in respect of this Guaranty shall be in writing, and delivered by hand or by registered mail (return receipt requested), overnight courier service or given by facsimile (except for a demand for payment) and addressed or directed as follows:

If to the Guarantor:

NSTAR
Attention : Senior Vice President Strategy, Law & Policy, General Counsel and Clerk
800 Boylston Street
17th Floor
Boston, Massachusetts 02199
United States of America
Facsimile: (781)441-3712

If to the Beneficiary:

H.Q. HYDRO RENEWABLE ENERGY, INC.
Attention: Christian G. Brosseau, President
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada
H2Z 1A4
Facsimile: (514)289-5484

or such address as the Guarantor or the Beneficiary may give notice to the other party, from time to time.

Section 12. Successors; No Third-Party Beneficiaries. This Guaranty shall be binding upon the Guarantor, its successors and permitted assigns. This Guaranty shall inure to the benefit of the Beneficiary and its successors and permitted assigns. This Guaranty is not intended to create any third-party beneficiaries.

Section 13. Governing Law. This Guaranty shall be governed by and construed in accordance with the laws of the State of New York (without regard to principles of conflict of laws that would direct for application of the laws of another jurisdiction).

Section 14. Submission to Jurisdiction. Each of the Guarantor and the Beneficiary hereto consents to submit itself to the exclusive jurisdiction of any state or federal court of competent jurisdiction located in the State of New York, United States of America, with respect to any dispute that arises under this Guaranty or in connection with the transactions contemplated hereby, and irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of or relating to this Guaranty or the transactions contemplated hereby in (a) the courts of the State of New York in New York County, or (b) the United States District Court for the Southern District of New York, and hereby further irrevocably and unconditionally waives and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum.

Section 15. Waiver of Jury Trial. EACH PARTY HEREBY KNOWINGLY, VOLUNTARILY, AND INTENTIONALLY WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS GUARANTY OR THE AGREEMENT.

Section 16. Entire Agreement. This Guaranty constitutes the entire agreement of the Guarantor and the Beneficiary pertaining to the subject matter hereof and supersedes all prior written or oral agreements and understandings between the Guarantor and the Beneficiary with respect to the subject matter hereof.

Section 17. Amendments. No amendments or modifications of or to any provision of this Guaranty shall be binding until in writing and executed by the Guarantor and the Beneficiary.

Section 18. Severability. If any one or more of the provisions of this Guaranty should be determined to be illegal or unenforceable, all other provisions shall remain effective.

Section 19. Interpretation. The word "including" when used in this Guaranty shall be deemed to be followed by "without limitation" or "but not limited to," whether or not it is in fact followed by such words or words of like import.

Section 20. Trustee Liability. No shareholder or trustee of the Guarantor shall be held to any liability whatever for the payment of any sum of money or for damages or otherwise under this Guaranty. This Guaranty shall not be enforceable against any such trustee in their or his or her individual capacities or capacity and this Guaranty shall be enforceable against the trustees of the Guarantor only as such, and every Person having any claim or demand arising under this Guaranty and relating to the Guarantor, its shareholders or trustees shall look solely to the trust estate of the Guarantor for the payment or satisfaction thereof.

Section 21. Counterparts. This Guaranty may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Guarantor and the Beneficiary acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

EXECUTION COPY

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

NSTAR

By: _____
Name: Philip J. Lembo
Title: Vice President and Treasurer
Date: October 4, 2010

Accepted:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: _____
Name:
Title:
Date:

EXECUTION COPY

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

NSTAR

By: _____
Name:
Title:
Date:

Accepted:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: _____
Name: CHRISTIAN G. BROSSEAU
Title: PRESIDENT
Date: 04 10 10

EXECUTION COPY

NORTHEAST UTILITIES

GUARANTY AGREEMENT

This Guaranty Agreement ("Guaranty"), dated as of October 4, 2010, is made and entered into by **Northeast Utilities**, a public utility holding company organized and existing as a voluntary trust under the laws of the Commonwealth of Massachusetts and having its head office and principal place of business at One Federal Street, Springfield, MA 01105, United States of America (hereinafter referred to as the "Guarantor"), in favor of **H.Q. Hydro Renewable Energy, Inc.**, a corporation organized and existing under the laws of the State of Delaware and having its principal place of business at 75, René-Lévesque Boulevard West, Montréal, QC, Canada, H2Z 1A4 (hereinafter referred to as the "Beneficiary").

WHEREAS the Beneficiary and **Northern Pass Transmission LLC,** a limited liability company organized and existing under the laws of the State of New Hampshire and having its place of business at Energy Park, 780 North Commercial Street, Manchester, NH 03101, United States of America (hereinafter referred to as "NPT"), have executed a Transmission Service Agreement, dated as of October 4, 2010 (hereinafter referred to as the "Agreement") (capitalized terms used but not defined in this Guaranty to have the meaning accorded such terms in the Agreement);

WHEREAS the Guarantor indirectly owns, through a wholly-owned subsidiary, a portion of the beneficial ownership interests in NPT and will directly or indirectly benefit from the Agreement; and

WHEREAS the Beneficiary has required that the Guarantor guarantee to the Beneficiary payment of all obligations of NPT under the Agreement, and the Guarantor has agreed to guarantee such obligations, subject to a maximum dollar limitation and the other terms and conditions provided in this Guaranty;

NOW THEREFORE, in consideration of the premises and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Guarantor hereby agrees with the Beneficiary as follows:

Section 1. Guaranty.

(a) Guaranteed Obligations. The Guarantor absolutely, irrevocably, and unconditionally guarantees to the Beneficiary, its successors and endorsees and assignees, as primary obligor and not merely as a surety, (i) the payment of all present and future amounts owed by NPT to the Beneficiary under the Agreement (including payment of NPT's indemnification obligations), not later than the date that is thirty (30) days after a written demand by the Beneficiary upon the Guarantor stating that NPT has failed to pay any such amount when due under the Agreement after demand therefor in accordance with the Agreement; provided, that the aggregate liability of the Guarantor under this Section 1(a) shall not exceed $18,750,000.00, plus (ii) payment of all third-party, out-of-pocket costs or expenses reasonably incurred by the Beneficiary to enforce its rights against the Guarantor under this Guaranty

including reasonable attorneys' fees, court costs and similar costs (such amounts and such costs and expenses hereinafter collectively called "Guaranteed Obligations"); provided, further, that it shall be a condition precedent to the Guarantor's obligations under this Guaranty that the Operation Phase shall have commenced under the Agreement; provided, further, that, subject to Section 8 of this Guaranty, this Guaranty shall terminate when and as provided in Section 9 of this Guaranty.

(b) Guaranty of Payment and Not Collection. This Guaranty is a guaranty of payment and not merely of collection.

(c) Information. At the Guarantor's request, the Beneficiary shall provide the Guarantor with any useful information respecting the content and the terms and conditions of the Guaranteed Obligations and a statement of account with details of billings and payments; provided, that such a request by the Guarantor shall not delay or prevent the Guarantor from paying under this Guaranty.

Section 2. Nature of Guaranty. The Guarantor's obligations hereunder shall be subject to all the contractual protections, limitations, waivers, exclusions and rights that NPT has under the Agreement, and the Guarantor shall be entitled to the benefits of any modification of, amendment to, waiver of or consent to departure from, the Agreement to the extent, if any, NPT would have been entitled to such benefits. Nonetheless, this Guaranty shall not be deemed discharged, impaired or affected by the existence, validity, enforceability, perfection, or extent of any collateral for any obligations under the Agreement of NPT.

Section 3. Consents, Waivers and Renewals. The Guarantor agrees that the Beneficiary may at any time and from time to time, either before or after maturity thereof, without notice to or further consent of the Guarantor, extend the time of payment of any of NPT's obligations under the Agreement, or accept, exchange or surrender any collateral therefor, or renew the Agreement, and may also make any agreement with NPT or with any other party to, or Person liable for any of the obligations contemplated in, the Agreement, or interested therein, for the extension, renewal, payment, compromise, discharge or release thereof, in whole or in part, or for any modification of the terms thereof or of any agreement between the Beneficiary and NPT or any such other party or Person, without in any way impairing or affecting this Guaranty. The obligations of the Guarantor hereunder are independent of the obligations of NPT, and the Guarantor agrees that the Beneficiary may resort to the Guarantor for payment of the Guaranteed Obligations, whether or not the Beneficiary shall have resorted to any collateral security, or shall have proceeded against any other obligor principally or secondarily obligated with respect to any of the Guaranteed Obligations, and whether or not NPT is joined in an action or proceeding against the Guarantor or a separate action or actions are brought against NPT.

Section 4. Subrogation. In any case, including NPT's insolvency, the Guarantor will not exercise any rights that it may acquire by way of subrogation, and hereby waives, to the fullest extent permitted by Applicable Law, any right to enforce any remedy that the Beneficiary now has or may hereafter have against NPT in respect of the Guaranteed Obligations. Notwithstanding the foregoing, upon full, final and indefeasible payment of all Guaranteed Obligations, the Guarantor shall be subrogated to the rights of the Beneficiary against NPT and the Beneficiary agrees to take, at the Guarantor's expense, such steps as the Guarantor may

reasonably request to implement such subrogation; provided, that, if a bankruptcy court in a bankruptcy proceeding of NPT issues a stay or injunction prohibiting or preventing the Guarantor from amending this Guaranty, as contemplated by Section 17.1.2 of the Agreement, based in whole or in part on the effects on the estate of NPT of any increase in the aggregate liability of the Guarantor under Section 1(a) of this Guaranty after the entry of an order of relief with respect to NPT from the amount of the aggregate liability of the Guarantor under Section 1(a) of this Guaranty in the Owner Guaranty prior to such amendment, and/or on the effects on the estate of NPT of the Guarantor's rights of subrogation resulting from such increase, then, in either such case, the Guarantor's waiver set forth in this Section 4 shall be absolute and permanent with respect to the portion of the Guaranteed Obligations equal to the amount of such increase; provided, further, that nothing in this Section 4 or in Section 8 of this Guaranty shall be construed to prevent the Guarantor from opposing or seeking to terminate such stay or injunction or any request of a third party for such a stay or injunction, in such bankruptcy proceeding.

Section 5. Waiver; Cumulative Rights. No waiver of any provision of this Guaranty shall be binding unless in a writing signed by the Beneficiary and specifically referring to this Guaranty. No failure on the part of the Beneficiary to exercise, and no delay in exercising any right, remedy or power hereunder shall operate as a waiver thereof, nor shall any waiver nor any single or partial exercise by the Beneficiary of any right, remedy or power hereunder preclude any other future exercise of any right, remedy or power. Each and every right, remedy and power hereby granted to the Beneficiary or allowed to it by Applicable Law or other agreement shall be cumulative and not exclusive of any other, and may be exercised by the Beneficiary from time to time.

Section 6. Waivers.

(a) Waiver of Notice. The Guarantor waives notice of the acceptance of this Guaranty, notice of dishonor, presentment and demand, except as set forth in Section 1 of this Guaranty, notice of exercise of any right and all other notices whatsoever.

(b) Absolute Guaranty. To the fullest extent permitted by Applicable Law, and except as limited by the express terms hereof, the liability of the Guarantor under this Guaranty shall be absolute, unconditional and irrevocable irrespective of, and the Guarantor waives any right or defense arising out of: (i) the lack of power or authority of the Guarantor to execute and deliver this Guaranty or of NPT to execute and deliver the Agreement; (ii) the failure of NPT to exist as a legal entity or the consolidation or merger of NPT with or into any other corporation or other entity, or the sale, lease or other disposition by NPT of all or substantially all of its assets to any other business entity; (iii) any disposal, transfer, assignment or other disposition or all or any part of the direct or indirect interest of the Guarantor in NPT; (iv) the bankruptcy, insolvency, dissolution, administration, reorganization, or liquidation of NPT, the admission in writing by NPT of its inability to pay its debts as they mature, or its making of a general assignment for the benefit of, or entering into a composition or arrangement with creditors or similar proceeding (whether such right or defence is available to the Guarantor, NPT, as debtor, or NPT's trustee or receiver); (v) any failure to give to the Guarantor notice of default in the making of any payment due and payable under this Guaranty or the Agreement, or notice of any failure on the part of NPT to do any act or thing or to observe or perform any covenant, condition or agreement by it to be observed or performed under the Agreement, except for the obligations to make demand for

payment as set forth under Section 1 of this Guaranty; (vi) the absence, impairment or loss of any right of reimbursement, contribution or subrogation or any other right or remedy of the Guarantor against NPT; (vii) subject to Section 2 of this Guaranty, any amendment, modification or extension of the Agreement; (viii) any assertion or claim that the automatic or other stay provided by Section 362 of the Bankruptcy Code or the equivalent legislation of any other country arising upon the voluntary or involuntary bankruptcy proceeding of NPT shall operate or be interpreted to stay, interdict, condition, reduce or inhibit the ability of the Beneficiary to enforce any rights that the Beneficiary may have against the Guarantor; and (ix) any other circumstances whatsoever (with or without knowledge of the Beneficiary or the Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge or defense of the Guarantor under this Guaranty, in bankruptcy or in any other instance, including all defenses of a guarantor or surety generally, other than full, final and indefeasible payment of the Guaranteed Obligations by the Guarantor and/or NPT.

Section 7. Representations and Warranties.

The Guarantor represents and warrants that:

a) It is a public utility holding company duly organized as a voluntary trust, validly existing and in good standing under the laws of the jurisdiction of its formation and has full voluntary trust power to execute, deliver and perform this Guaranty;

b) The execution, delivery and performance of this Guaranty have been and remain duly authorized by all necessary voluntary trust action and do not contravene any provision of any Applicable Law applicable to or binding on the Guarantor or any of its properties or the Guarantor's constitutional documents or any contractual restriction binding on the Guarantor or its assets and that the individual or individuals executing this Guaranty for and on behalf of the Guarantor have been duly authorized to do so;

c) This Guaranty constitutes a legal, valid and binding obligation of the Guarantor enforceable against the Guarantor in accordance with its terms, subject, as to enforcement, to bankruptcy, insolvency, reorganization and other similar laws and to general principles of equity; and

d) There is no pending or, to the best of the Guarantor's knowledge, threatened action or proceeding affecting the Guarantor before any Governmental Authority that might reasonably be expected to materially and adversely affect the ability of the Guarantor to perform its obligations under this Guaranty.

Section 8. Setoff and Counterclaims; Bankruptcy. Notwithstanding anything in this Guaranty to the contrary, the Guarantor shall be entitled to assert all rights and defenses that NPT may be entitled to under the Agreement, including any setoff or counterclaims that NPT is or may be entitled to under the Agreement, except that the Guarantor shall not be entitled to any rights or defenses arising out of the matters described in clauses (i) through (viii) of Section 6(b) of this Guaranty. Notwithstanding anything in Section 9 of this Guaranty to the contrary, the obligations of the Guarantor under this Guaranty automatically shall be reinstated if and to the extent that, for any reason, any payment by or on behalf of NPT in respect of the Guaranteed Obligations is rescinded or must be otherwise restored by any holder of any of the Guaranteed

Obligations, whether as a result of any proceedings in bankruptcy or reorganization or otherwise. The Guarantor hereby agrees not to seek an injunction or otherwise seek to stay its liability under this Guaranty in any voluntary or involuntary bankruptcy proceeding of NPT and, in the event such injunction or stay issues at the instance of a third party, to take such steps as may be necessary or appropriate to seek to terminate or dissolve any such injunction or stay.

Section 9. Termination.

(a) Continuing Guaranty. The Guarantor acknowledges that the Beneficiary has entered into the Agreement in reliance on this Guaranty being a continuing and irrevocable agreement and the Guarantor agrees that this Guaranty may not be revoked in whole or in part, except that this Guaranty and the Guarantor's liability hereunder may be terminated as provided in this Section 9.

(b) Expiration. This Guaranty is a continuing guarantee effective upon the commencement of the Operation Phase. The Guarantor's obligations with respect to the Guaranteed Obligations shall expire upon the full, final and indefeasible payment of such Guaranteed Obligations.

(c) Transfer. Upon any Transfer by NPT that is permitted by Section 23.1 of the Agreement, including (i) the approval of such Transfer by the Beneficiary, (ii) the assumption in writing by the Transferee of NPT's obligations associated with the Transferred portion of the Agreement, which assumption is not subject to conditions that have not been satisfied or waived, and (iii) delivery to the Beneficiary of any replacement security or other financial assurances to be provided by on or behalf of the Transferee in connection with such Transfer in accordance with the Agreement, then, provided, that an Owner Default shall not have occurred and be continuing, (x) the obligations of the Guarantor hereunder shall terminate to the extent of the Transferred portion of the Agreement and the Guarantor shall be fully, finally, and unconditionally released from all liability with respect thereto associated with the Transferred portion of the Agreement (it being understood that the aggregate liability of the Guarantor under Section 1(a) of this Guaranty shall be reduced in proportion to the Transferred portion of the Agreement), and (y) at the request of the Guarantor, the Beneficiary shall execute and deliver to the Guarantor a full, final, and unconditional release of the Guaranteed Obligations, in such form as the Guarantor may reasonably request, with respect to the Transferred portion of the Agreement. For the avoidance of doubt, this Section 9(c) does not apply to any Transfer permitted by Section 23.2 or Section 23.3 of the Agreement.

Section 10. Assignment. The Guarantor shall not be entitled to assign its rights, interest or obligations hereunder to any other Person without the prior written consent of the Beneficiary. The Beneficiary shall be entitled to assign its rights, interest or obligations hereunder solely in connection with an assignment of the Agreement permitted pursuant to the terms of the Agreement.

Section 11. Notices. All notices or other communications in respect of this Guaranty shall be in writing, and delivered by hand or by registered mail (return receipt requested), overnight courier service or given by facsimile (except for a demand for payment) and addressed or directed as follows:

If to the Guarantor:

NORTHEAST UTILITIES
Attention: Vice President and Treasurer
c/o Northeast Utilities Service Company
56 Prospect Street
Hartford, CT 06103
United States of America
Facsimile: (860)728-4632

With a copy to:

NORTHEAST UTILITIES
Attention: Senior Vice President and General Counsel
c/o Northeast Utilities Service Company
56 Prospect Street
Hartford, CT 06103
United States of America
Facsimile: (860)728-4581

If to the Beneficiary:

H.Q. HYDRO RENEWABLE ENERGY, INC.
Attention: Christian G. Brosseau, President
75, René-Lévesque Boulevard West, 18th Floor
Montréal (Québec) Canada
H2Z 1A4
Facsimile: (514)289-5484

or such address as the Guarantor or the Beneficiary may give notice to the other party, from time to time.

Section 12. Successors; No Third-Party Beneficiaries. This Guaranty shall be binding upon the Guarantor, its successors and permitted assigns. This Guaranty shall inure to the benefit of the Beneficiary and its successors and permitted assigns. This Guaranty is not intended to create any third-party beneficiaries.

Section 13. Governing Law. This Guaranty shall be governed by and construed in accordance with the laws of the State of New York (without regard to principles of conflict of laws that would direct for application of the laws of another jurisdiction).

Section 14. Submission to Jurisdiction. Each of the Guarantor and the Beneficiary hereto consents to submit itself to the exclusive jurisdiction of any state or federal court of competent jurisdiction located in the State of New York, United States of America, with respect to any dispute that arises under this Guaranty or in connection with the transactions contemplated hereby, and irrevocably and unconditionally waives any objection to the laying of venue of any action, suit or proceeding arising out of or relating to this Guaranty or the transactions contemplated hereby in (a) the courts of the State of New York in New York County, or (b) the United States District Court for the Southern District of New York, and hereby further irrevocably and unconditionally waives

and agrees not to plead or claim in any such court that any such action, suit or proceeding brought in any such court has been brought in an inconvenient forum.

Section 15. Waiver of Jury Trial. EACH PARTY HEREBY KNOWINGLY, VOLUNTARILY, AND INTENTIONALLY WAIVES ANY RIGHTS IT MAY HAVE TO A TRIAL BY JURY IN RESPECT OF ANY LITIGATION BASED HEREON OR ARISING OUT OF, UNDER, OR IN CONNECTION WITH, THIS GUARANTY OR THE AGREEMENT.

Section 16. Entire Agreement. This Guaranty constitutes the entire agreement of the Guarantor and the Beneficiary pertaining to the subject matter hereof and supersedes all prior written or oral agreements and understandings between the Guarantor and the Beneficiary with respect to the subject matter hereof.

Section 17. Amendments. No amendments or modifications of or to any provision of this Guaranty shall be binding until in writing and executed by the Guarantor and the Beneficiary.

Section 18. Severability. If any one or more of the provisions of this Guaranty should be determined to be illegal or unenforceable, all other provisions shall remain effective.

Section 19. Interpretation. The word "including" when used in this Guaranty shall be deemed to be followed by "without limitation" or "but not limited to," whether or not it is in fact followed by such words or words of like import.

Section 20. Trustee Liability. No shareholder or trustee of the Guarantor shall be held to any liability whatever for the payment of any sum of money or for damages or otherwise under this Guaranty. This Guaranty shall not be enforceable against any such trustee in their or his or her individual capacities or capacity and this Guaranty shall be enforceable against the trustees of the Guarantor only as such, and every Person having any claim or demand arising under this Guaranty and relating to the Guarantor, its shareholders or trustees shall look solely to the trust estate of the Guarantor for the payment or satisfaction thereof.

Section 21. Counterparts. This Guaranty may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Guarantor and the Beneficiary acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

EXECUTION COPY

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

NORTHEAST UTILITIES

By: _____
Name: David R. McHale
Title: Executive Vice President and Chief Financial Officer
Date: October 4, 2010

Accepted:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: _____
Name:
Title:
Date:

EXECUTION COPY

IN WITNESS WHEREOF, the Guarantor hereto has executed this Guaranty, as of the date first set forth above.

NORTHEAST UTILITIES

By: _____
Name:
Title:
Date:

Accepted:

H.Q. HYDRO RENEWABLE ENERGY, INC.

By: _____
Name: CHRISTIAN G. BROSSEAU
Title: PRESIDENT
Date: 04-10-10

ATTACHMENT F

Subordination Terms

1. Definitions. For purposes of this Attachment F, capitalized terms that are defined in the Transmission Service Agreement, dated as of October 4, 2010 (as amended, amended and restated, supplemented, waived or otherwise modified, the "Agreement"), by and between Northern Pass Transmission LLC, as Owner, and H.Q. Hydro Renewable Energy, Inc., as Purchaser, shall have the same meanings as those set forth in the Agreement. In addition, the following terms shall have the following meanings:

"Collateral" means, at any time, all property or assets (including limited liability company membership interests) subject to (or intended by the Loan Documents or the Agreement to be subject to) a Senior Lien or a Junior Lien.

"Collateral Proceeds" has the meaning set forth in Paragraph 9.

"DIP Financing" has the meaning set forth in Paragraph 10.2.

"Discharge of Project Debt Obligations" means, except to the extent otherwise expressly provided in Paragraph 13: (a) the indefeasible payment in full in cash and discharge of the principal of, and interest on, all indebtedness outstanding under the Loan Documents and constituting Project Debt Obligations; (b) the indefeasible payment in full in cash and discharge of all other Project Debt Obligations that are due and payable or otherwise accrued and owing at or prior to the time such principal and interest are paid; (c) termination or expiration of all commitments, if any, to extend credit that would constitute Project Debt Obligations; and (d) termination or cash collateralization of all letters of credit issued under the Loan Documents and constituting Project Debt Obligations.

"Junior Lien" means any Lien that presently exists or that may exist or arise at any time hereafter securing the TSA Obligations, including those under the Purchaser's Security Documents.

"Lien" means any lien, mortgage, pledge, assignment, security interest, fixed or floating charge or encumbrance of any kind (including any conditional sale or other title retention agreement, any lease in the nature thereof, and any agreement to give any security interest) and any option, trust or deposit or other preferential arrangement having the practical effect of any of the foregoing.

"Owner Party" means Owner and the members of Owner pledging membership interests in Owner as Collateral.

"Proceeding" means: (a) any voluntary or involuntary case or proceeding under the Bankruptcy Code with respect to any Owner Party; (b) any other voluntary or involuntary insolvency, reorganization or bankruptcy case or proceeding, or any receivership, liquidation, reorganization or other similar case or proceeding with respect to any Owner Party or with respect to a material portion of its respective assets; (c) any liquidation, dissolution,

reorganization or winding up of any Owner Party whether voluntary or involuntary and whether or not involving insolvency or bankruptcy; or (d) any assignment for the benefit of creditors or any other marshalling of assets and liabilities of any Owner Party.

"Recovery" has the meaning set forth in Paragraph 13.

"Senior Lien" means any Lien that presently exists or that may exist or arise at any time hereafter securing the Project Debt Obligations, including any Lien under the Loan Documents.

"Standstill Period" has the meaning set forth in Paragraph 4(a)(i).

"TSA Obligations" means the obligations of Owner under the Agreement secured by the Purchaser Security Documents.

2. Subordination of Junior Lien.

2.1 Any and all Senior Liens shall be prior and superior in all respects to any and all Junior Liens. Any and all Junior Liens shall be junior and subordinate in all respects to any and all Senior Liens. For the avoidance of doubt and as set forth in Section 17.2.2 of the Agreement, any and all Junior Liens shall be superior in priority to all indebtedness (other than the Project Debt Obligations) of Owner secured by the Collateral.

2.2 The provisions of Paragraph 2.1 shall apply irrespective of:

(a) the date, time, order, manner or method of grant, attachment or perfection of the Liens created by any Loan Document or any Purchaser's Security Document;

(b) the date, time, order, manner or method of filing or recording of financing statements or other documents filed or recorded to perfect Liens on any Collateral;

(c) the rules for determining perfection or priority under the Uniform Commercial Code or any other law governing the relative priorities of secured creditors; or

(d) any defect or deficiency in, or failure to attach or perfect, the Senior Liens or the Junior Liens.

2.3 Nothing in the Subordination Agreement shall (a) restrict or interfere with the exercise of Purchaser's rights and remedies under the Agreement, whether as set forth thereunder, at law or in equity, except with respect to Purchaser's rights and remedies in respect of Junior Liens, (b) prevent Owner from making, or prevent Purchaser from receiving, payments under the Agreement at any time, so long as such receipt is not the direct or indirect result of the exercise by Purchaser of rights or remedies in respect of the Junior Liens, or enforcement thereof, in contravention of the Subordination Agreement, or (c) otherwise affect or limit the obligations of Owner under the Agreement, the Purchaser's Security Documents or the Loan Documents. The Subordination Agreement shall be solely for the benefit of Purchaser and the Financing Parties and not of any other Person (including any Owner Party).

2.4 The parties to the Subordination Agreement intend that the Collateral subject to the Senior Lien and the Collateral subject to the Junior Lien shall be the same. In furtherance of the foregoing, the parties to the Subordination Agreement agree, subject to the other provisions hereof, upon request by the Financing Parties or Purchaser, to cooperate in good faith (and to direct their counsel to cooperate in good faith) from time to time in order to determine (a) the specific items included in the Collateral subject to the Senior Lien and the Collateral subject to the Junior Lien, and (b) the steps to be taken to perfect their respective Liens thereon.

3. Subordination Respecting Additional Advances. Without limiting the provisions of Paragraph 2, the Junior Liens are, and shall be, expressly subject and subordinate in all respects to the Senior Liens that secure any and all advances made at any time or from time to time on or with respect to the Project Debt Obligations, whenever made, including any and all of such advances, interest, charges, fees and expenses that may increase the indebtedness evidenced and secured by the Loan Documents.

4. Exercise of Remedies.

(a) Until the Discharge of Project Debt Obligations has occurred, whether or not any Proceeding has been commenced by or against Owner or any other Owner Party, Purchaser:

(i) will not exercise or seek to exercise any rights or remedies (including setoff and credit bid) under the Purchaser's Security Documents or the Junior Liens with respect to any Collateral or institute any action or proceeding with respect to such rights or remedies (including any action of foreclosure or any Proceeding); provided, that Purchaser may exercise any or all such rights or remedies after a period of at least one hundred eighty (180) days has elapsed (such one hundred eighty (180)-day period, the "Standstill Period") since the date on which Purchaser has notified the Financing Parties that Purchaser is permitted to enforce any or all of its rights and remedies under the Purchaser's Security Documents in accordance with Section 15.4(e) of the Agreement, if the Owner Default giving rise to such rights or remedies shall then be continuing; provided, further, that, notwithstanding anything herein to the contrary, in no event shall Purchaser exercise any rights or remedies under the Purchaser Security Documents or the Junior Liens with respect to the Collateral if, notwithstanding the expiration of the Standstill Period, the Financing Parties shall have commenced and be diligently pursuing the exercise of their rights or remedies with respect to all or any material portion of the Collateral (prompt notice of such exercise to be given by the Financing Parties to Purchaser).

(ii) will not contest, protest or object to any foreclosure proceeding or action brought by a Financing Party or any other exercise by a Financing Party of any rights and remedies relating to the Collateral under the Loan Documents or the Senior Liens consistent with the Subordination Agreement, the Agreement and Applicable Law; and

(iii) will not object to the forbearance by a Financing Party from bringing or pursuing any foreclosure proceeding or action or any other exercise of any rights or remedies relating to the Senior Liens or the Collateral, in each case, so long as the Junior

Liens attach to the proceeds thereof, subject to the relative priorities described in Paragraph 2.

(b) Notwithstanding the foregoing, Purchaser may:

(i) file a claim or statement of interest with respect to the TSA Obligations; provided, that a Proceeding has been commenced by or against Owner;

(ii) take any action (not adverse to the priority status of the Senior Liens, or the rights of any Financing Party to exercise remedies in respect thereof as provided in the Subordination Agreement) in order to create, perfect, preserve or protect the Junior Liens;

(iii) file any necessary responsive or defensive pleadings in opposition to any motion, claim, adversary proceeding or other pleading made by any Person objecting to or otherwise seeking the disallowance or avoidance of the claims of Purchaser or of the Junior Liens, including any claims secured by the Collateral, if any, in each case in accordance with the terms of the Subordination Agreement; and

(iv) vote on any plan of reorganization, file any proof of claim, make other filings and make any arguments and motions that are, in each case, in accordance with the terms of the Subordination Agreement, with respect to the TSA Obligations and the Collateral; provided, that Purchaser shall not (A) vote against any plan of reorganization supported by the Financing Parties unless Purchaser's negative vote as a general unsecured creditor in a class of claims that includes other general unsecured creditors (assuming that its full claim were voted as a general unsecured claim) would be sufficient to result in such class voting to not accept such plan of reorganization, or (B) vote in favor of, or otherwise support, a plan of reorganization not supported by the Financing Parties unless Purchaser's affirmative vote as a general unsecured creditor in a class of claims that includes other general unsecured creditors (assuming that its full claim were voted as a general unsecured claim) would be sufficient to result in such class voting to accept such plan of reorganization.

(c) Subject to Paragraphs 4(a) and (b) and Paragraph 10.4(b):

(i) Purchaser agrees that it will not take any action that would hinder any exercise of remedies under the Loan Documents or Senior Liens or that is otherwise prohibited hereunder, including any sale, lease, exchange, transfer or other disposition of the Collateral, whether by foreclosure or otherwise;

(ii) Purchaser hereby waives any and all rights it may have as a junior lien creditor or otherwise to notice of any action by the Financing Parties seeking to enforce or collect the Project Debt Obligations or the Senior Liens granted in any of the Collateral undertaken in accordance with the Subordination Agreement, regardless of whether or not any action or failure to act by or on behalf of the Financing Parties is adverse to the interests of Purchaser;

(iii) Purchaser hereby waives any and all rights it may have as a junior lien creditor or otherwise to object to the manner in which the Financing Parties seek to enforce or collect the Project Debt Obligations or the Senior Liens granted in any of the Collateral undertaken in accordance with the Subordination Agreement, regardless of whether or not any action or failure to act by or on behalf of the Financing Parties is adverse to the interests of Purchaser; and

(iv) Purchaser hereby acknowledges and agrees that no covenant, agreement or restriction contained in the Purchaser's Security Documents shall be deemed to restrict in any way the rights and remedies of the Financing Parties with respect to the Collateral as set forth in the Subordination Agreement and the Loan Documents.

(d) Anything to the contrary in the Subordination Agreement notwithstanding, and both before and during any Proceeding, except as specifically prohibited by Paragraphs 4(a)(i) and 4(c), Purchaser may take any actions and exercise any and all rights and remedies that would be available to a holder of unsecured claims against Owner in accordance with the Agreement and Applicable Law.

5. Non-Disturbance. So long as the Agreement has not been terminated in accordance with its terms, Purchaser's rights under the Agreement shall not be disturbed, diminished or interfered with by the Financing Parties, and the Financing Parties shall not take any action or request any relief or remedy that would terminate the Agreement or otherwise impair Purchaser's rights thereunder, notwithstanding any rights the Financing Parties may have against Owner under the Loan Documents or otherwise. If, pursuant to the Loan Documents, the Financing Parties or their designee forecloses on or enters into possession of the Northern Pass Transmission Line or other Collateral, then, provided the Agreement has not been terminated in accordance with its terms, the Financing Parties or such designee, as the case may be, and any transferee of the Northern Pass Transmission Line or other Collateral or an interest therein, shall be bound by all of the terms of the Agreement and the Agreement shall continue in full force and effect as if such party had taken the place of Owner under the Agreement; provided, however, that recourse to the Financing Parties or their designee in respect of the Agreement shall be limited to the Collateral. Should the Financing Parties sell, assign, or otherwise transfer the Northern Pass Transmission Line or other Collateral or an interest therein prior to the termination of the Agreement in accordance with its terms, such transfer shall be expressly conditioned on the transferee agreeing to be bound by the terms of the Agreement. If, (a) pursuant to the Loan Documents, the Financing Parties or their designee forecloses on, or enters into possession of, the Northern Pass Transmission Line or other Collateral, and (b) the Agreement is rejected or terminated as a result of any Proceeding affecting Owner, then if, within thirty (30) days after the occurrence of such an event, Purchaser shall so request, Purchaser and the Financing Parties or their designee or a transferee, as applicable, shall execute and deliver a new agreement having identical terms as the Agreement (subject to any conforming changes necessitated by the substitution of parties); provided, that (i) the term under the new agreement shall be no longer than the remaining balance of the term specified in the Agreement, and (ii) prior to the execution of such new agreement, Purchaser shall cure any outstanding payment and performance defaults under the Agreement, excluding any performance defaults that, by their nature, are incapable of being cured, and upon execution of such new agreement, Purchaser and the Financing Parties or their

designee or a transferee, as applicable, shall be liable for all obligations arising under such new agreement.

6. Actions Respecting Collateral.

6.1 Until the Discharge of Project Debt Obligations has occurred, the Financing Parties shall, except as otherwise expressly provided herein, have the exclusive right to enforce rights, exercise remedies (including setoff and credit bid) and make determinations regarding the release, disposition or restrictions of Collateral and may exercise their rights and remedies under the Loan Documents and the Senior Liens in any manner in their sole discretion in compliance with Applicable Law, and without consultation with or the consent of Purchaser, whether in a Proceeding or otherwise. The Financing Parties' rights and remedies under the Subordination Agreement shall not be prejudiced by any action omitted or undertaken by it with respect to the Project Debt or any security therefor, consistent with the Loan Documents and the Subordination Agreement, and Purchaser hereby irrevocably and unconditionally waives all of the following:

(a) notice of acceptance by the Financing Parties of the Subordination Agreement;

(b) notice of the existence or creation or non-payment of any Project Debt Obligations; and

(c) all diligence in collection or protection of or realization upon the Project Debt Obligations or any security therefor.

6.2 The Financing Parties may, without affecting the priority of Liens contemplated hereby, do all or any of the following, all in the sole discretion of the Financing Parties and without regard for the effect thereof on Purchaser: (a) release any security for the Project Debt Obligations (including that provided by the Loan Documents or by any guaranty or letter of credit) or retain or obtain a security interest in other property to secure any or all of the Project Debt Obligations; (b) release, obtain or retain the primary or secondary obligation of any guarantor or endorser or any other Person with respect to any or all of the Project Debt Obligations; (c) to the extent Owner is not prohibited from doing so under the Agreement, refinance, extend, renew, defease, amend, modify, supplement, restructure, replace, refund or repay, or issue other indebtedness, in exchange or replacement for, the Project Debt, in whole or in part; and (d) obtain satisfaction of the Project Debt Obligations from the Collateral without proceeding to enforce any guaranty, letter of credit, or other collateral or security for any of the Project Debt Obligations or any other right or remedy.

6.3 In connection with (a) an enforcement of any Senior Lien or of the rights or remedies with respect to the Project Debt Obligations or (b) a disposition of assets, which enforcement or disposition (x) is expressly permitted by the Agreement and (y) does not, by the terms of the Agreement, require as a consequence of such enforcement or disposition that the Agreement be assumed by the purchaser of such assets, the Junior Lien shall be released on any such assets constituting Collateral at the time and to the extent the Senior Lien on such Collateral is released by the Financing Parties. Purchaser hereby appoints the Financing Parties as attorney-in-fact for the purposes of releasing such Collateral.

6.4 Purchaser shall not, in any Proceeding or otherwise, oppose any sale or disposition of the Collateral or any part thereof that is supported by the Financing Parties and is in compliance with the Agreement, the Subordination Agreement, and Applicable Law, and Purchaser will be deemed to have consented under Section 363 of the Bankruptcy Code (and otherwise) to any such sale of the Collateral or any part thereof supported by the Financing Parties; provided, that the proceeds thereof are applied to the reduction of the Project Debt Obligations and thereafter in the manner contemplated by Paragraph 7.1.

6.5 Unless and until the Discharge of Project Debt Obligations has occurred, the Financing Parties shall have the sole and exclusive right, subject to the rights of the Owner Parties under the Loan Documents, to adjust settlement for any insurance policy covering the Collateral in the event of any loss thereunder and to approve any award granted in any condemnation or similar proceeding (or any deed in lieu of condemnation) affecting the Collateral. Unless and until the Discharge of Project Debt Obligations has occurred, and subject to the rights of the Owner Parties under the Loan Documents, all proceeds of any such policy and any such award (or any payments with respect to a deed in lieu of condemnation) in respect of the Collateral shall be paid to the Financing Parties pursuant to the terms of the Loan Documents (including for purposes of cash collateralization of letters of credit) and thereafter, to the extent that (a) the Discharge of Project Debt Obligations has occurred and (b) Purchaser would be entitled to such proceeds under the second sentence of Paragraph 7.1, to Purchaser. Until the Discharge of Project Debt Obligations has occurred, if Purchaser shall, at any time, receive any proceeds of any such insurance policy or any such award or payment in contravention of the Subordination Agreement, it shall pay such proceeds over to the Financing Parties in accordance with the last sentence of Paragraph 7.1.

7. Proceeds.

7.1 So long as the Discharge of Project Debt Obligations has not occurred, whether or not any Proceeding has been commenced by or against Owner, any Collateral or proceeds thereof received in connection with the sale or other disposition of, or collection on, such Collateral upon the exercise of remedies by a Financing Party, shall be applied by the Financing Parties to the Project Debt Obligations in such order as specified in the Loan Documents. Upon the Discharge of Project Debt Obligations, if (a) there has been and continues to be an Owner Default under the Agreement, (b) the amount of damages suffered by Purchaser as a result of such Owner Default has been agreed in writing between Owner and Purchaser or determined in accordance with Article 18 of the Agreement, and (c) Owner shall not have paid such amount on or before the date specified for payment in such written agreement or within fourteen (14) Business Days after the date of such determination, as applicable, the Financing Parties shall then deliver to Purchaser any Collateral and proceeds of Collateral held by any Financing Party in the same form as received, with any necessary endorsements or as a court of competent jurisdiction may otherwise direct to be applied by Purchaser to the TSA Obligations in such order as specified in the Purchaser's Security Documents.

7.2 If

(a) Purchaser shall receive any Collateral or proceeds of any Collateral in contravention of the Subordination Agreement, or

(b) the Senior Liens do not attach to, or are not perfected or enforceable with respect to, any Collateral for any reason, and Purchaser shall receive any distribution or recovery with respect to, or allocable to, the value of such Collateral or any proceeds, thereof, then Purchaser agrees that any such Collateral, distribution, recovery or proceeds shall (for so long as the Discharge of Project Debt Obligations has not occurred) be segregated and held in trust and forthwith paid over to the Financing Parties in the same form as received without recourse, representation or warranty (other than a representation of Purchaser that it has not otherwise sold, assigned, transferred or pledged any right, title or interest in and to such distribution or recovery), but with any necessary endorsements or as a court of competent jurisdiction may otherwise direct until such time as the Discharge of Project Debt Obligations has occurred. The Financing Parties are hereby authorized to make any such endorsements as agent for Purchaser. This authorization is coupled with an interest and is irrevocable.

8. Covenants.

8.1 So long as the Discharge of Project Debt Obligations has not occurred, Purchaser hereby agrees that it will not modify or amend any of the Purchaser's Security Documents, without the Financing Parties' prior express written consent (other than to conform the Purchaser's Security Documents to modifications or amendments to the Financing Parties' security documents to the extent consistent with Section 17.2.1 of the Agreement). The Financing Parties shall notify Purchaser of any such modifications or amendments.

8.2 So long as the Discharge of Project Debt Obligations has not occurred, Purchaser shall not, without the prior written consent of the Financing Parties, sell, assign, or otherwise transfer, in whole or in part, any rights in the Purchaser's Security Documents to any other Person unless (1) such action is made in connection with an assignment of the Agreement to such Person that is permitted in accordance with the terms of the Agreement, (2) such action is made expressly subject to the Subordination Agreement and (3) the transferee expressly acknowledges to the Financing Parties, by a writing in form and substance reasonably satisfactory to the Financing Parties, the subordination provided for in the Subordination Agreement and agrees to be bound by all of the terms thereof.

8.3 The Financing Parties agree to hold that part of the Collateral that is in their possession or control (or in the possession or control of their agents or bailees) to the extent that possession or control thereof is taken to perfect a Lien thereon under the Uniform Commercial Code as bailee for Purchaser (such bailment being intended, among other things, to satisfy the requirements of Sections 8-301(a)(2) and 9-313(c) of the Uniform Commercial Code) and any assignee of Purchaser, solely for the purpose of perfecting the security interest granted under the Purchaser's Security Documents. The Financing Parties shall have no obligation whatsoever to Purchaser to ensure that the Collateral is genuine or owned by any of the Owner Parties or to preserve rights or benefits of any Person except as expressly set forth in this Paragraph 8.3. The duties and responsibilities of the Financing Parties to Purchaser under this Paragraph 8.3 shall be limited solely to holding the Collateral as bailee in accordance with this Paragraph 8.3 and delivering the Collateral upon a Discharge of Project Debt Obligations as provided in the Subordination Agreement. The Financing Parties acting pursuant to this Paragraph 8.3 shall not have a fiduciary relationship in respect of Purchaser.

9. Liquidation; Dissolution; Bankruptcy. Without limitation of the provisions of Paragraph 2.3(b), upon any payment or distribution of Collateral of any kind or character, whether in cash, securities or other property, to creditors of Owner in a liquidation or dissolution of Owner, whether voluntary or involuntary, or in a Proceeding relating to Owner or its property or creditors ("Collateral Proceeds"):

(a) the Financing Parties shall be entitled to receive payment in full, in cash or cash equivalents, of the Project Debt Obligations before Purchaser or any other holder of the TSA Obligations shall be entitled to receive, for or on account of the Purchaser's Security Documents, any payment of Collateral Proceeds with respect to any TSA Obligations or on account of any purchase or other acquisition of any TSA Obligations by Owner; and

(b) so long as the Discharge of Project Debt Obligations has not occurred, any payment or distribution of Collateral Proceeds for or on account of the Purchaser's Security Documents, to which Purchaser would be entitled but for this Paragraph 9, shall be made by Owner or by any receiver, trustee in bankruptcy, liquidating trustee, agent or other Person making such payment of distribution, directly to the Financing Parties to the extent necessary to pay all such Project Debt Obligations in full.

10. Proceedings.

10.1 Each of (a) Purchaser and (b) the Financing Parties agrees that it will not (and hereby waives any right to) contest, or support any other Person in contesting, in any proceeding (including any Proceeding), any Project Debt Obligation or TSA Obligation or the priority, validity or enforceability of any Senior Lien or Junior Lien, as the case may be, or the provisions of the Subordination Agreement; provided, that nothing in the Subordination Agreement shall be construed to prevent or impair the rights of the Financing Parties or Purchaser to enforce the Subordination Agreement, including the provisions of the Subordination Agreement relating to the priority of the Senior Liens and Junior Liens.

10.2 Until the Discharge of Project Debt Obligations has occurred, if Owner or any other Owner Party shall be subject to any Proceeding and the Financing Parties shall desire to permit (a) the use of cash collateral on which the Financing Parties or any other creditor has a Lien or (b) Owner or any other Owner Party to obtain financing, whether from the Financing Parties or any other Person, under Section 364 of the Bankruptcy Code ("DIP Financing"), then Purchaser agrees that it will raise no objection to the use of such cash collateral or to such DIP Financing, respectively, and to the extent the Senior Liens are subordinated to, or *pari passu* with, such DIP Financing, Purchaser will subordinate the Junior Liens in the Collateral to the Liens securing such DIP Financing (and all obligations relating thereto) and will not request adequate protection or any other relief in connection therewith (except as expressly agreed by the Financing Parties or to the extent permitted by Paragraph 10.4); provided, that the aggregate principal amount of the DIP Financing, plus the aggregate outstanding principal amount of Project Debt Obligations, does not exceed the principal amount of Project Debt permitted to constitute Project Debt Obligations in accordance with the second sentence of the definition thereof, and Purchaser retains the right to object to any ancillary agreements or arrangements regarding the use of cash collateral or the DIP Financing that are materially prejudicial to Purchaser's interests. Purchaser agrees that it will not raise any objection or oppose a motion to sell or otherwise dispose of any

Collateral free and clear of the Junior Liens or other claims under Section 363 of the Bankruptcy Code if (i) the requisite Financing Parties have consented to such sale or disposition of such assets, (ii) such motion does not impair the rights of Purchaser under Section 363(k) of the Bankruptcy Code, and (iii) the Junior Liens attach to the proceeds of such sale or disposition subject to the relative priorities described in Paragraph 2.

10.3 If any Financing Party is required in any Proceeding or otherwise to turn over or otherwise pay to the estate of Owner or any other Owner Party any amount paid in respect of Project Debt Obligations, then such Financing Party shall be entitled to a reinstatement of Project Debt Obligations with respect to all such recovered amounts.

10.4 The following provisions shall apply with respect to requests for adequate protection:

(a) Purchaser agrees that it shall not contest (or support any other Person in contesting):

(i) any request by the Financing Parties for adequate protection; or

(ii) any objection by the Financing Parties to any motion, relief, action or proceeding based upon the Financing Parties claiming a lack of adequate protection.

(b) Notwithstanding the foregoing provisions in this Paragraph 10.4, in any Proceeding:

(i) if the Financing Parties (or any subset thereof) are granted adequate protection in the form of additional collateral in connection with any use of cash collateral or any DIP Financing, then Purchaser may seek or request adequate protection in the form of a Lien on such additional collateral, which Lien will be subordinated to the Liens on such cash collateral and to the Senior Liens or the Liens securing the DIP Financing (and all obligations relating thereto) on the same basis as the other Junior Liens are so subordinated to the Senior Liens under such Subordination Agreement; and

(ii) in the event Purchaser seeks or requests adequate protection in respect of the TSA Obligations and such adequate protection is granted in the form of additional collateral, then Purchaser agrees that the Financing Parties shall also be granted a Lien on such additional collateral as security for the Project Debt Obligations and for any cash collateral use or DIP Financing provided by the Financing Parties and that any Lien on such additional collateral securing the TSA Obligations shall be subordinated to the Senior Lien on such additional collateral and the Lien on such additional collateral securing any such DIP Financing provided by the Financing Parties (and all obligations relating thereto) and to any other Liens granted to the Financing Parties as adequate protection on the same basis as the other Junior Liens are so subordinated to such Senior Liens under the Subordination Agreement.

Except as otherwise expressly set forth in Paragraph 10.2, this Paragraph 10.4 or in connection with the exercise of remedies with respect to the Collateral, nothing herein shall limit the rights of Purchaser from seeking adequate protection with respect to its rights in the Collateral in any

Proceeding (including adequate protection in the form of a cash payment, periodic cash payments or otherwise).

10.5 Except as otherwise expressly provided herein, nothing contained in the Subordination Agreement shall prohibit or in any way limit the Financing Parties from objecting in any Proceeding or otherwise to any action taken by Purchaser, including the asserting by Purchaser of any of its rights and remedies under the Agreement or the Purchaser's Security Documents.

11. Subrogation. Following the Discharge of the Project Debt Obligations, Purchaser shall be subrogated to the rights of the Financing Parties to receive distributions of assets of Owner or payment by or on behalf of Owner made on the Project Debt Obligations, until all TSA Obligations shall be paid in full.

12. Further Assurances. So long as the Discharge of Project Debt Obligations has not occurred, Purchaser shall, within a reasonable time after request by the Financing Parties, execute, acknowledge and deliver to the Financing Parties any and all further other instruments in recordable form on such terms and conditions as may be customary for transactions of a similar nature and as may be reasonably satisfactory to Purchaser and the Financing Parties to further, advance, implement, confirm, evidence or facilitate the purposes addressed in the Subordination Agreement.

13. Avoidance Issues. If any Financing Party is required in any Proceeding or otherwise to turn over or otherwise pay to the estate of Owner any amount paid in respect of Project Debt Obligations (a "Recovery"), then such Financing Party shall be entitled to a reinstatement of Project Debt Obligations with respect to all such recovered amounts. If the Subordination Agreement shall have been terminated prior to such Recovery, the Subordination Agreement shall be reinstated in full force and effect, and such prior termination shall not diminish, release, discharge, impair or otherwise affect the obligations of the parties hereto from such date of reinstatement.

14. Notation on the Purchaser Mortgage. Purchaser agrees that, promptly after any Subordination Agreement has been executed and the Financing Parties thereunder furnish to Purchaser the relevant recordation information, Purchaser will cause the following statement to be typed or printed conspicuously at the top of the first page of the Purchaser Mortgage (including by an amendment to the Purchaser Mortgage with respect to any Subordination Agreement executed after the Purchaser Mortgage is initially filed) "This instrument and the obligations it evidences or secures are subject to the provisions of that certain Subordination Agreement dated as of _____, 20__, a memorandum of which is recorded in Book [____], page [____], [_____] County, New Hampshire."

EXECUTION COPY

ATTACHMENT G

Letter Agreement

Please see the attached.

EXECUTION COPY

October 4, 2010

Mr. Christian G. Brosseau
Vice President, Wholesale Markets
Hydro-Québec Production
75 West, René-Lévesque Blvd, 18th Floor
Montréal (Québec) Canada H2Z 1A4

Re: Letter Agreement for Recovery of Northern Pass Transmission Line Project Development Costs

Dear Mr. Brosseau:

As you are aware, Northern Pass Transmission LLC ("NPT") and H.Q. Hydro Renewable Energy, Inc. ("HQRE"), an indirect, wholly owned subsidiary of Hydro-Québec, acting through its Hydro-Québec Production division ("HQP") (NPT and HQP also referred to herein individually as a "Party", or collectively as the "Parties"), have entered into a Transmission Service Agreement of even date herewith ("TSA") that governs the rates, terms and conditions under which HQRE will acquire firm transmission service from NPT over a 1,200 MW high voltage direct current transmission line that will run from Québec to a point in New Hampshire ("Northern Pass Transmission Line Project"). The TSA will be filed with the Federal Energy Regulatory Commission ("FERC") for acceptance as a rate schedule.

Upon the termination of the TSA at any time prior to the commencement of the Construction Phase (as that term is defined in the TSA), HQP has agreed to reimburse NPT for certain Project Development Costs (as defined below), as further set forth in Appendix A. By this letter agreement, the Parties seek to confirm their agreement regarding reimbursement of the Project Development Costs.

1. **Execution Date; FERC Effective Date.** This letter agreement shall be binding and effective as of the date first set forth above (the "Execution Date"); *provided, however*, that any payment hereunder shall be subject to prior acceptance by FERC of this letter agreement ("FERC Effective Date"). A copy of this letter agreement is an attachment to the TSA that will be filed with FERC. NPT shall, however, file a copy of this letter agreement with FERC with a request for approval or acceptance only upon the occurrence of a PDC Payment Event.

2. **Project Development Costs; PDC Payment Event.** "Project Development Costs" mean the following costs incurred by NPT: (a) the Owner's Costs (as defined in the TSA) and (b) unless NPT has terminated the TSA, the costs and expenses associated with the drafting and negotiation of the TSA, in each case, from January 1, 2009 through the occurrence of a PDC Payment Event (as defined below) (the "Reimbursement Period").

Project Development Costs reimbursable under this letter agreement shall not exceed twelve million dollars ($12,000,000) (the "NTX Amount"). The Parties may by mutual written agreement increase the NTX Amount, however, neither NPT nor its affiliates shall have any obligation to incur Project Development Costs in accordance with a particular schedule or timeframe, or in excess of the NTX Amount.

For purposes of this letter agreement, a "PDC Payment Event" means the termination of the TSA by NPT or HQRE prior to the commencement of the Construction Phase or the rejection by FERC of the TSA.

3. **Reimbursement of Project Development Costs.** Subject to the terms and conditions of this letter agreement, HQP shall reimburse NPT, in accordance with this Section 3, for the Project Development Costs set forth in Appendix A attached hereto that NPT has incurred and will incur pursuant to this letter agreement. HQP approves the Project Development Costs incurred by NPT through August 31, 2010 (as shown in Section II of Appendix A).

3.1. **Monthly Allocations.** Section III of Appendix A contains monthly cash flow allocations for the period of September 1, 2010 through March 31, 2011. NPT shall not, in any month, incur Project Development Costs that, when combined with Project Development Costs previously incurred, exceed the total cumulative cash flow allocations through such month, unless and until NPT provides HQP a written explanation of the reason(s) for incurring such excess Project Development Costs and obtains HQP's consent to incur such excess Project Development Costs.

3.2. **Monthly Reports.** For each month following the Execution Date, NPT shall, within a reasonable time after the last day of each such month, provide HQP with a report reasonably detailing the Project Development Costs incurred during such month prior to the occurrence of a PDC Payment Event, if any. If HQP objects to any costs identified in such a report, HQP shall, within fourteen (14) calendar days, provide NPT with written notice of, and the basis for, such objection. NPT may, in its sole discretion, suspend the activities associated with the Project Development Costs that are the subject of an HQP objection (and the incurrence of such costs and expenses) until such objection is resolved by mutual agreement of the Parties.

3.3. **PDC Payment Event Invoices.** Following the occurrence of a PDC Payment Event, NPT shall submit to HQP a preliminary invoice(s) of all Project Development Costs incurred during the Reimbursement Period, but not to exceed the NTX Amount.

3.4. **Billing and Payment.** Within thirty (30) days after the FERC Effective Date, NPT shall render a final invoice(s) of Project Development Costs incurred during the Reimbursement Period (which invoiced amounts shall be consistent with Appendix A, the monthly reports, the NTX Amount and the conditions, if any, in the FERC order accepting or approving this letter agreement) to HQP at the

address specified in Appendix B. HQP shall pay such final invoice(s) within thirty (30) calendar days of its receipt of such final invoice. All payments shall be made in immediately available funds payable to NPT, or by wire transfer to a bank named and account designated by NPT. Neither payment of such final invoice(s) by HQP, nor acceptance of payment by NPT, shall constitute a waiver of any rights or claims NPT or HQP may have under this letter agreement or the TSA.

4. **Term.** Unless otherwise agreed to by the Parties in writing, this letter agreement shall expire upon the earlier to occur of the commencement of the Construction Phase and the indefeasible payment in full by HQP to NPT of all amounts owed to NPT by HQP under this letter agreement.

5. **Termination.** Except as set forth in Sections 4 and 6, this letter agreement may only be terminated by mutual agreement of the Parties in writing.

6. **Effect of TSA.** Notwithstanding any other provision herein to the contrary, the Parties acknowledge and agree that, following the expiration or other termination of this letter agreement pursuant to its terms, the Parties rights and responsibilities concerning Project Development Costs (regardless of when incurred) shall be governed by the TSA and any FERC order accepting or approving the TSA, and HQP and its affiliates shall be without liability or obligation whatsoever under this letter agreement (including any payment or reimbursement obligation). Upon the commencement of the Construction Phase, the TSA shall supersede this letter agreement in its entirety and, except as set forth in Section 7, this letter agreement shall cease to have any further force and effect.

7. **Survival.** This letter agreement shall continue in effect after termination or expiration only to the extent necessary to provide for final billings, if any, and payments, if any, for Project Development Costs incurred in accordance with this letter agreement, and to permit the determination and enforcement of obligations arising while this letter agreement was in effect.

8. **Assignment.** No full or partial assignment by a Party of its interests under this letter agreement shall be valid without the express written consent of the other Party, which consent shall not be unreasonably withheld, delayed or conditioned.

9. **Notices.** Unless otherwise provided in this letter agreement, any notice, demand or request required or permitted to be given by either Party to the other and any instrument required or permitted to be tendered or delivered by either Party to the other shall be effective when delivered in writing and may be so given, tendered or delivered, by facsimile or email to the facsimile numbers or email addresses set out in Appendix B, or by recognized national courier, or by depositing the same with the United States Postal Service with postage prepaid, for delivery by certified or registered mail, addressed to the Party, or personally delivered to the Party, at the address set out in Appendix B.

   Either Party may change the notice information in this letter agreement by giving seven (7) calendar days written notice prior to the effective date of the change.

10. **Governing Law; Disputes**. This letter agreement and the rights and duties of the Parties shall be governed by and construed, enforced and performed in accordance with the laws of the State of New York, without regard to its principles of conflicts of law. THE PARTIES HEREBY CONSENT TO THE EXCLUSIVE JURISDICTION OF THE COURTS OF THE STATE OF NEW YORK FOR ENFORCEMENT OF THIS LETTER AGREEMENT AND ANY OTHER LEGAL PROCEEDINGS ARISING OUT OF OR RELATING TO THE LETTER AGREEMENT AND THE TRANSACTIONS CONTEMPLATED UNDER THE LETTER AGREEMENT. EACH PARTY HEREBY IRREVOCABLY WAIVES AND RELEASES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, (a) ANY OBJECTION TO THE VENUE OF ANY SUCH PROCEEDING BROUGHT IN SUCH A COURT AND (b) ANY CLAIM THAT ANY SUCH PROCEEDING BROUGHT IN SUCH COURT HAS BEEN BROUGHT IN AN INCONVENIENT FORUM.

11. **Amendments; Entire Agreement.** No provision in this letter agreement may be amended or waived except by a written instrument signed by the Parties. This letter agreement, and the TSA, constitute the entire understanding and agreement between the Parties with respect to the subject matter herein and supersede all prior representations and agreements, express or implied, oral or written with respect to the subject matter herein. References herein to this letter agreement shall include a reference to all attachments, including the Appendices.

12. **Confidentiality.** HQP shall not share with or otherwise disclose to Hydro-Québec TransÉnergie or any other Hydro-Québec division, subsidiary or affiliate with responsibility for construction of electric transmission and/or distribution facilities, the vendor specific rates or information contained in any invoices or other documentation provided to HQP or HQRE by NPT or NPT's members or affiliates pursuant to this letter agreement. Such information provided by NPT, if any, shall be held by HQP and HQRE as confidential and subject to the terms and conditions of that certain Confidentiality Agreement, dated as of February 29, 2008, by and between Northeast Utilities Service Company and H.Q. Energy Services (U.S.) Inc., the terms of which, to the extent not otherwise inconsistent with this letter agreement, are hereby incorporated herein and made a part hereof.

13. **Counterparts.** This letter agreement may be executed in two or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute but one and the same instrument. The Parties acknowledge and agree that any document or signature delivered by facsimile or electronic transmission shall be deemed to be an original executed document for all purposes hereof.

If HQP agrees to the foregoing terms of this letter agreement, please indicate HQP's agreement by having the appropriate respective duly authorized officer of HQP and HQRE countersign both originals of this letter agreement and returning one executed original to me.

EXECUTION COPY

Thank you for your care and attention to this matter,

Sincerely,

NORTHERN PASS TRANSMISSION LLC

James A. Muntz
President

AGREED AND ACCEPTED BY
HYDRO-QUÉBEC PRODUCTION

Christian G. Brosseau
Its Vice-President – Wholesale Markets, duly authorized

* * * * * *

The undersigned H.Q. Hydro Renewable Energy, Inc. acknowledges having read this letter agreement and agrees to be bound by the terms thereof, including Section 12.

H.Q. HYDRO RENEWABLE ENERGY, INC.

Christian G. Brosseau
President, duly authorized

EXECUTION COPY

Thank you for your care and attention to this matter,

Sincerely,

NORTHERN PASS TRANSMISSION LLC

_____

James A. Muntz
President

AGREED AND ACCEPTED BY
HYDRO-QUÉBEC PRODUCTION

Christian G. Brosseau
Its Vice-President – Wholesale Markets, duly authorized

* * * * * *

The undersigned H.Q. Hydro Renewable Energy, Inc. acknowledges having read this letter agreement and agrees to be bound by the terms thereof, including Section 12.

H.Q. HYDRO RENEWABLE ENERGY, INC.

Christian G. Brosseau
President, duly authorized

Appendix A

I. Scope of Project Development Cost Activities

NPT has and will, subject to the terms of the letter agreement, incur the Project Development Costs as defined in Section 2 of the letter agreement for the costs set forth in Sections II and III of this Appendix A.

II. Project Development Costs Incurred Through August 2010

For the period January 1, 2009 through August 31, 2010, NPT has incurred Project Development Costs for work/services in support of the Northern Pass Transmission Line Project in the aggregate amount of **seven million six hundred three thousand six hundred dollars (US$7,603,600.00)**.

III. Monthly Allocations of Project Development Costs September – March 2011

For the period of September 1, 2010 through March 31, 2011, NPT anticipates that NPT will incur Project Development Costs for work/services in support of the Northern Pass Transmission Line Project in the aggregate amount of approximately **eight million three hundred sixty thousand one hundred dollars (US$8,360,100.00)** and in the monthly allocations set forth below. The foregoing is an estimate only. Actual costs incurred may be higher or lower depending on factors such as the Northern Pass Transmission Line Project schedule, changes in scope, changes in law, or unanticipated regulatory issues.

Category of Activity[1]	Jan. 2009 – Aug. 2010	Sept. 2010	Oct. 2010	Nov. 2010*	Dec. 2010**	Jan. 2011	Feb. 2011	Mar. 2011	Total Sept 2010 – Mar. 2011	Total Jan. 2009 – Mar. 2011
Legal	**1252.1**	**325.0**	**335.0**	**150.0**	**200.0**	**180.0**	**180.0**	**180.0**	**1550.0**	**2802.1**
Environmental	**979.7**	**380.0**	**380.1**	**90.0**	**72.0**	**50.0**	**50.0**	**50.0**	**1072.1**	**2051.8**
Routing Analysis & Preliminary Engineering	**1205.5**	**277.5**	**435.5**	**528.5**	**460.5**	**378.5**	**353.5**	**391.5**	**2825.5**	**4031.0**
Real Estate Services	**389.8**	**90.0**	**75.0**	**75.0**	**50.0**	**80.0**	**80.0**	**80.0**	**530.0**	**919.8**

[1] All amounts are in thousands (1,000s) of dollars.

Corporate Communications & Community Outreach	**308.3**	**40.3**	**20.0**	**25.0**	**25.0**	**10.0**	**10.0**	**10.0**	**140.3**	**448.6**
Miscellaneous	**223**	**43.9**	**51.2**	**56.9**	**62.2**	**67.1**	**71.9**	**76.8**	**430.0**	**653.0**
NPT Labor	**1734.1**	**214.2**	**215.5**	**224.6**	**224.1**	**223.0**	**222.7**	**223.1**	**1547.2**	**3281.3**
TSA Negotiation Costs	**1511.1**	**215.0**	**50.0**	**0**	**0**	**0**	**0**	**0**	**265.0**	**1776.1**
Cumulative Cash Flow Total	**7603.6**	**1585.9**	**1562.3**	**1150.0**	**1093.8**	**988.6**	**968.1**	**1011.4**	**8360.1**	**15,963.7**

*** Based on the monthly allocations, Project Development Costs will total $11,901,800.00 by November 30, 2010.**
**** Based on the monthly allocations, Project Development Costs will total $12,995,600.00 by December 31, 2010. NPT therefore anticipates that NPT will have incurred $12,000,000.00 in Project Development Costs, and reached the NTX Amount, by approximately early December 2010. At an appropriate time before the NTX Amount is reached, the Parties will consult on whether to increase the NTX Amount or curtail project development activities.**

Time Value of Money Charge

NPT will accrue, on a cumulative basis, a charge, equal to the time value of money, on all Project Development Costs. Such charge shall accrue against all Project Development Costs at an annual rate of 6.4% as of the Execution Date**,** and shall be adjusted monthly thereafter.

Appendix B

I. Addresses for Delivery of Notices and Billings

Notices:

NPT:
James A. Muntz, President
Northeast Utilities Service Company
107 Selden Street
Berlin, CT 06037
(860) 665-3315

with a copy to:

Duncan MacKay, Deputy General Counsel
Northeast Utilities Service Company
107 Selden Street
Berlin, CT 06037
(860) 665-3495

HQP:
Christian G. Brosseau, Vice President, Wholesale Markets
Hydro-Québec Production
75 West, René-Lévesque Blvd, 18th Floor
Montréal (Québec) Canada H2Z 1A4

Billings and Payments:

NPT:
Anne Bartosewicz, Project Director
Northeast Utilities
107 Selden Street
Berlin, CT 06037

HQP:
Maxime Lanctôt, Director, Business Development & Expertise
Hydro-Québec Production
75 West, René-Lévesque Blvd, 17th Floor
Montréal (Québec) Canada H2Z 1A4

II. Alternative Forms of Delivery of Notices

NPT:
Fax: (860) 665-6717 (attention James A. Muntz)
Email: muntzja@nu.com

HQP:
Fax: (514) 289-5484 (attention Christian G. Brosseau)
Email: brosseau.christian@hydro.qc.ca

ATTACHMENT H

Example of Calculation of Levelized Monthly Decommissioning Payment

This example is intended to illustrate the methodology for the calculation of the Levelized Monthly Decommissioning Payment. This example and the numbers used in this example are purely illustrative and are in no way intended to supersede Section 9.3 of the Agreement or the Formula Rate.

Formula

Levelized Monthly Decommissioning Payment equals:

Estimated Net Decommissioning Cost, multiplied by Decommissioning Payment Formula

"Decommissioning Payment Formula" means the following formula:

$$\frac{c}{[(1 + c)^{60} - 1]}$$

Where:

c is the reasonably expected monthly rate of return on amounts deposited into the Decommissioning Fund (expressed as a percentage).

Assumptions

Estimated Net Decommissioning Cost, expressed in dollars for the year(s) during which they are expected to be incurred and then discounted to their present value at the beginning of the first calendar day after the end of the Decommissioning Payment Period, is $1,000,000.

Reasonably expected monthly rate of return on amounts deposited into the Decommissioning Fund (c) is 0.40 percent.

Solving this equation, step by step

Levelized Monthly Decommission Payment equals:

1. $1,000,000 * (0.0040 / (((1 + 0.0040)^60) – 1))

2. $1,000,000 * (0.0040 / (((1.0040)^60) – 1))

3. $1,000,000 * (0.0040 / ((1.27064072) – 1))

4. $1,000,000 * (0.0040 / (0.27064072))

5 $1,000,000 * (0.01477974)

6. $14,779.74

Pursuant to Section 9.3.3(a) of the Agreement, $14,779.74 would be included in the Formula Rate for each month during the Decommissioning Payment Period.

ATTACHMENT I

Example of Calculation of Refund of Amounts Subject to Late Payment Interest

This example is intended to illustrate the methodology for the calculation of a subsequent refund of a late payment. This example and the numbers used in this example are purely illustrative and are in no way intended to supersede Section 14.5(c) of the Agreement or the first sentence of Section 14.5 of the Agreement

Assumptions

Interest Rate = 12 percent per annum (compounded monthly)

June 2011 Billing

Invoice Amount	$1,000
Date of Invoice	June 1, 2011
Due Date	June 15, 2011
Payment Date	July 1, 2011

The total amount due on the date of payment is $1,005, which amount is computed by adding $1,000 (the original amount invoiced) and $5 (the ½ month late interest fee).

Subsequent Refund

If later, on July 1, 2012, the aforesaid payment is required to be refunded, the refund will equal the $1,000 payment made on July 1, 2011 (the original amount invoiced), plus the interest accrued on that $1,000 payment from the due date of June 15, 2011 to the date of refund on July 1, 2012. To ensure that the refund does not double recover interest, the following language has been included in Section 14.5(c) of the Agreement: "If all or a portion of the amount [*here, the $1,000 payment due on June 15, 2011*] to which such interest relates [*here, the $5 late interest fee*] is later refunded pursuant to this Agreement [*here, on July 1, 2012*], then, in calculating that refund, such interest [*here, $5*] shall not be included in the refund.

Appendix A-1

Summary of the TSA

Article 1 – Definitions and Rules of Interpretation

Article 1 defines terms used in the TSA and lists general rules of construction for the TSA.

Article 2 – Regulatory Filings and Required Approvals

Northern Pass is required to file the TSA with the Commission under Section 205 of the Federal Power Act. If the Commission issues an order accepting or approving the TSA on conditions that are unacceptable to one of the parties, the parties may agree on amendments to the TSA or request a rehearing. Both parties have general obligations of cooperation in connection with all regulatory requirements and governmental approvals, and neither party nor its affiliates shall undertake any action that is inconsistent with the TSA before the Commission or any other governmental entity.

Article 3 – Effective Date; Term

The term of the TSA is 40 years from the start of commercial operations, subject to certain termination and early termination payments, including the following:

- By mutual agreement of the parties.
- By either party for convenience until 45 days after issuance of the Commission order approving or accepting the TSA.
- By Northern Pass, if any U.S. construction approval is unlikely to be obtained within three years after the effective date of the Commission order, or is likely to contain unacceptable conditions, or if the pursuit of such approval may have a material adverse effect on Northern Pass or its affiliates.
- By HQ Hydro Renewable, if any Canadian construction approval or the approval of ISO-NE or Northeast Power Coordinating Council, Inc. to operate the NPT Line at 1,200 MW is unlikely to be obtained within three years after the date of the Commission order, or is likely to contain unacceptable

conditions, or if the pursuit of any Canadian construction approval may have a material adverse effect on HQ Hydro Renewable or its affiliates.

- By HQ Hydro Renewable upon a budget increase of more than 15 percent over the immediately preceding budget or 30 percent over the preliminary budget.
- By HQ Hydro Renewable if any of the construction contracts or the construction loan agreement between its affiliates and Northern Pass are terminated as a result of a default by Northern Pass under such agreement(s).
- By HQ Hydro Renewable for convenience during construction. HQ Hydro Renewable is generally required to pay Northern Pass's costs plus AFUDC as accrued on applicable Northern Pass costs plus the greater of (a) 10 percent of the costs incurred by Northern Pass to date that would have been recoverable absent termination of the TSA and (b) $20,000,000.
- By HQ Hydro Renewable as a result of a loss occurrence during commercial operations rendering the NPT Line entirely out-of-service, where the uninsured costs to reconstruct exceed the formula set forth in the TSA.
- By HQ Hydro Renewable for convenience during commercial operations. HQ Hydro Renewable is required to pay Northern Pass's costs plus AFUDC as accrued on applicable Northern Pass costs and the net present value of the return on equity that Northern Pass would have received during the balance of the initial term, discounted at the base return on equity ("ROE").
- By Northern Pass or HQ Hydro Renewable upon certain defaults of the other, as specified in Article 15 of the TSA.

Article 4 – Commercial Operation

The TSA provides that eight conditions precedent must be satisfied or waived to achieve commercial operation of the NPT Line, including the commissioning of the NPT Line, construction of the NPT Line and the Québec Line in accordance with the maximum amount of electric power for which they are designed to transfer, and completion of certain AC upgrades to the New England transmission system.

If, because of a default by Northern Pass, the commercial operation date does not occur within 180 days after the later of its target commercial operations date and the date

the Québec Line is ready for start-up and testing, AFUDC and carrying charges will cease to accrue. If the delay continues beyond the second anniversary of that initial deadline, Northern Pass is required to reimburse HQ Hydro Renewable for any penalties and fees owed by an affiliate of HQ Hydro Renewable to another of its affiliates, TransÉnergie, capped at the equivalent of six months of arm's length transmission service payments payable for the Québec Line under the TransÉnergie OATT.

If the commercial operation date is delayed for reasons other than a default by Northern Pass, AFUDC and carrying charges continue to accrue on all costs incurred to date. If the delay continues for more than two years after the later of the NPT Line's target commercial operations date and the date the NPT Line is ready for start-up and testing, the commercial operation date will be deemed to occur on such second anniversary, and HQ Hydro Renewable's obligation to pay transmission service payments will commence on that date.

Article 5 – General Rights and Responsibilities of the Parties

During the construction phase, Northern Pass agrees, among other things, to (a) use Good Utility Practice (as defined in the TSA) to construct the NPT Line in accordance with the maximum amount of electric power for which it is designed to transfer, (b) use commercially reasonable efforts to obtain required approvals, and (c) provide certain budgets, estimates and progress reports. The budgets are subject to review by the management committee established under the TSA.

The parties agree to certain obligations for the negotiation of a construction contract with an affiliate of HQ Hydro Renewable, a construction loan agreement with Hydro-Québec, and future term loans to replace the initial construction loan.

Northern Pass agrees to finance a portion of the NPT Line costs through equity contributions that will maintain the agreed capital structure and that Northern Pass, NU and NSTAR will enter into an equity commitment agreement for this purpose, which agreement will be pledged to Hydro-Québec as construction lender.

Article 6 – Procedures for Operation and Maintenance of NPT Line

As of the commercial operation date, Northern Pass agrees to transfer operational control of the NPT Line to ISO-NE. Thereafter, Northern Pass agrees, among other things, to (a) provide firm transmission service, (b) operate and maintain the NPT Line in accordance with Good Utility Practice and in compliance with applicable regulatory requirements, (c) provide annual operating and capital expense plans and budgets to the management committee for approval, and (d) provide a plan for any required extraordinary capital expense to the management committee for approval.

Costs provided for in a budget or plan approved by the management committee are not subject to a prudency challenge to the extent approved. If HQ Hydro Renewable's representative on the management committee votes against an activity provided for in a budget or plan, (a) Northern Pass will not be in breach of Good Utility Practice if it does not perform that activity and (b) HQ Hydro Renewable retains prudency challenge rights if Northern Pass nevertheless performs such activity.

Article 7 – HQ Hydro Renewable's Transmission Rights over NPT Line

Northern Pass will make available to HQ Hydro Renewable firm transmission service on the NPT Line up to 1,200 MW or any lesser amount established on commissioning of the NPT Line, together with, on a non-firm basis, any additional transmission service that is incidental to the design, engineering, construction or operation of the NPT Line and which is permitted to be scheduled for transmission service by ISO-NE.

Transmission service is to be provided at all times subject only to outages that limit the availability of the NPT Line under ISO-NE rules. Northern Pass is not liable to HQ Hydro Renewable, and HQ Hydro Renewable is obligated to continue paying transmission service payments to Northern Pass, if the NPT Line is not available, except to the extent the unavailability is caused by Northern Pass's failure to exercise good utility practice or otherwise discharge its TSA obligations (a "non-excused outage"). Upon the occurrence of a non-excused outage, the transmission service payment is reduced proportionately by the ratio that the unavailable capacity bears to the contract capacity (which is 1,200 MWs or any lesser amount established upon commissioning) for the period of the non-excused outage.

Additionally, upon the occurrence of a non-excused outage and after the unavailable capacity exceeds a specified threshold, Northern Pass is required to reimburse HQ Hydro Renewable for the lesser of the transmission service payments payable for the Québec Line under the TransÉnergie OATT or the cost of replacement

transmission service, such lesser amount being capped at six months' of transmission service payments under the TransÉnergie OATT.

Article 8 – Payment for Transmission Service over the NPT Line

Commencing on the commercial operation date of the NPT Line, HQ Hydro Renewable is required to pay monthly transmission service payments, as calculated pursuant to the Formula Rate, based on a projected cost-of-service calculation, with an annual true-up to actual costs.

The Formula Rate will include only costs and expenses that were prudently incurred. Subject to specified limitations (where the costs and expenses were approved by HQ Hydro Renewable or by an arbitrator or were deemed approved under certain provisions of the TSA), HQ Hydro Renewable may challenge the prudency of such costs and expenses by filing a pleading with the Commission to exclude such costs and expenses from the Formula Rate. Any such proceeding is to be conducted using normal Commission procedures and presumptions.

The parties agree that (a) the depreciable life of (i) the original assets will be 40 years and (ii) any capital additions placed in service after commercial operation will be equal to the lesser of their economic life and the remaining term as of the date placed in service, (b) Northern Pass will use commercially reasonable efforts to maintain a capital structure of 50-50 and will use a 50-50 capital structure to calculate transmission service payments under the Formula Rate, and (c) the ROE (i) will be 12.56 percent prior to the commercial operation date and (ii) thereafter, will be equal to the base ROE under the

ISO-NE Tariff, plus the lesser of 142 basis points or an amount that would not cause the ROE to exceed the applicable zone of reasonableness.

Northern Pass will enter into facilities agreements with the applicable transmission owner(s) for any additions or upgrades ("AC Upgrades") that are (a) required pursuant to Section I.3.9 of the ISO-NE Tariff to interconnect the NPT Line with the New England Transmission System, or (b) identified as part of ISO-NE's transmission project interconnection review under Section I.3.9, and desired by HQ Hydro Renewable. Amounts incurred under these agreements, with AFUDC or carrying charges, are recovered under the Formula Rate in the same manner as costs that are incurred for the HVDC Line.

If all or any portion of the AC Line meets the criteria for Pool Transmission Facilities ("PTF"), Northern Pass will have the right to transfer ownership of any such PTF to PSNH. Any such transfer will be on terms of an agreement between Northern Pass and PSNH providing for certain payments by Northern Pass to PSNH, which payments will be recovered under the Formula Rate provided they do not exceed the amounts that would have been payable under the TSA absent such transfer. Upon a reasoned basis, HQ Hydro Renewable may request Northern Pass or PSNH, as applicable, to determine that the costs and expenses of the AC Line should be included in the rates for Regional Transmission Service under the ISO-NE OATT. If Northern Pass or PSNH, as applicable, agrees that such regional rate treatment is consistent with its obligations, commitments to the Commission and other regulatory bodies and its affiliates, then Northern Pass or PSNH, as applicable, shall submit a request for such

treatment to ISO-NE, and, if approved by ISO-NE, HQ Hydro Renewable may accept such regional rate treatment or it may continue to bear responsibility for all or any portion of the costs and expenses of the transferred portion of the AC Line, in which case it is entitled to all financial and physical transmission rights associated with the portion of the AC Line for which it continues to bear cost responsibility.

Article 9 – Rights upon Expiration of Term

HQ Hydro Renewable has rollover rights at the end of the 40-year term in accordance with Order No. 890 *et seq.* and the Commission's pro forma open access transmission service tariff, as such rights are defined as of the effective date of the TSA. If there is another use of the NPT Line after the end of the term of the TSA, Northern Pass agrees to reimburse HQ Hydro Renewable for a pro rata portion of the costs and expenses of each capital addition that has an expected useful life beyond the end of the term.

The parties agree to detailed provisions for the decommissioning of the NPT Line, both upon expiration and early termination of the TSA, and the payment of decommissioning costs by HQ Hydro Renewable, including the allocation of such costs between HQ Hydro Renewable and any subsequent user of the NPT Line.

Article 10 – Resale of Transmission Service

If HQ Hydro Renewable determines that the transmission capacity of the NPT Line exceeds HQ Hydro Renewable's needs, HQ Hydro Renewable agrees to offer to sell such unused capacity in accordance with applicable law. Additionally, any capacity on the NPT Line not scheduled by HQ Hydro Renewable by the applicable scheduling

deadline for the following day is to be made available for resale to third parties. Any capacity available for resale, and its price, will be posted on an OASIS site. The parties agree to jointly contract with independent, non-affiliated third parties for use of an OASIS site and to carry out capacity release functions for daily and hourly resales and certain other functions that neither party elects to perform. Representatives of both parties will monitor the OASIS administrator. The costs of the OASIS administrator will be recovered under the Formula Rate.

The proceeds of any capacity releases and transmission resales will be credited, net of reasonable expenses, to amounts owed by HQ Hydro Renewable to Northern Pass.

Article 11 – Real Power Losses, Congestion and Capacity Resales

HQ Hydro Renewable is responsible for all power losses associated with the transmission service between the U.S. Border and the delivery point, except where these losses are due to Northern Pass's failure to exercise good utility practice or discharge its TSA obligations. HQ Hydro Renewable is entitled to (i) any financial transmission rights and other financial or physical rights associated with the NPT Line or, if paid for by HQ Hydro Renewable, the AC Upgrades, issued under the ISO-NE Tariff or rules or by ISO-NE, (ii) any other market products issued under the ISO-NE Tariff or rules or by ISO-NE that derive from the acquisition of transmission service over the NPT Line and that can be sold or have economic value, and (iii) any tie benefits or interconnection capability credits deemed applicable to the NPT Line. Northern Pass does not have to support, and Northern Pass's affiliates can challenge, the entitlements described in clauses (ii) or (iii).

Article 12 – Ancillary Services

HQ Hydro Renewable is responsible for any ancillary services required under the ISO-NE tariff in connection with the transmission of power over the NPT Line, and is entitled to the revenues from such ancillary services, net of the reasonable fees and expenses of providing such services.

Article 13 – Management

A management committee, comprising one representative of each party, will be established to coordinate and oversee the implementation and administration of the TSA and handle matters referred to it. The management committee will meet monthly during the construction period and quarterly during commercial operations. Decisions of the management committee will require a unanimous vote.

Article 14 – Billing and Payment

Monthly transmission payments are the quotient of the estimated revenue requirement for each year or partial year, divided by the number of calendar months in the year. The annual revenue requirement for the prior year is trued-up within 60 days after Northern Pass files its FERC Form 1 for such prior year. If the true-up discloses an excess, the excess will be refunded to HQ Hydro Renewable, with interest, in a single lump sum. If the true up discloses a deficiency, HQ Hydro Renewable will pay a surcharge in the amount of the deficiency, with interest, in a single lump sum.

HQ Hydro Renewable has no right to withhold any disputed payment, but, if the dispute is resolved in HQ Hydro Renewable's favor, Northern Pass will make a retroactive adjustment, refund all overpayments with interest, and conform future

invoices. Interest is calculated pursuant to 18 C.F.R. § 35.19a(a), as in effect during the period during which such interest is due.

Article 15 – Events of Default and Remedies

The events that constitute defaults by HQ Hydro Renewable or defaults by Northern Pass are listed and include, among other defaults, payment and performance defaults.

The remedies available to the parties and certain limitations on the remedies available to the parties are listed, including limitations on the parties' respective rights to terminate the TSA or suspend transmission service based on a HQ Hydro Renewable default or a Northern Pass default.

Article 16 – Force Majeure

A party is excused from performance of its non-payment obligations based on an event of force majeure, but must use commercially reasonable efforts to avoid and mitigate the event, consistent with Good Utility Practice (as defined in the TSA). If there is a 100 percent outage due to an event of force majeure that continues for more than 365 consecutive days, (a) the ROE portion of the transmission service payments and depreciation expenses are thereafter waived until firm transmission service is restored, (b) the term is extended by a period equal to the outage, and (c) the ROE portion of the transmission service payments and depreciation expenses are recovered over the period after service is restored through the end of the extended term. The term is also extended (on a month-to-month basis) where the average availability of the NPT Line in any month is less than 75 percent of contract capacity.

A loss occurrence during construction is subject to the provisions generally applicable to construction, including HQ Hydro Renewable's rights to terminate the TSA for material construction cost increases or for convenience, as described above. In the event of a loss occurrence during commercial operation, HQ Hydro Renewable has a right to terminate the TSA if there are material uninsured costs of reconstruction (more than 15 percent of unamortized rate base).

Article 17 – Financial Assurances

Hydro-Québec will issue a payment guaranty of (a) HQ Hydro Renewable's payment obligations under the TSA (excluding decommissioning costs), subject to a cap, (b) HQ Hydro Renewable's obligations for decommissioning costs, limited to the estimated cost of decommissioning the NPT Line on the date the TSA is terminated, and (c) certain costs of enforcement as provided in the guaranty. The cap referenced in (a) is initially set at $55,000,000. After delivery of the first construction budget, the cap is equal to the sum of (i) Northern Pass's costs, plus AFUDC as accrued on Northern Pass's costs, plus the greater of (A) 10 percent of the costs incurred by Northern Pass to date that are recoverable under the TSA and (B) $20,000,000, (ii) estimated wind-down costs, and (iii) fourteen months of budgeted construction costs, less (iv) amounts already paid by Hydro-Québec under the guaranty. During commercial operations, the cap is equal to the sum of (x) Northern Pass's applicable costs plus AFUDC, (xi) estimated wind-down costs and (xii) three years of budgeted capital costs. The guaranty will be reissued with the revised cap annually during construction and triennially during commercial

operations. Failure to reissue the guaranty is deemed a termination of the TSA for convenience by HQ Hydro Renewable.

NU and NSTAR will each issue a guaranty of Northern Pass's payment obligations under the TSA during commercial operations, subject to a combined aggregate cap of $25 million, and Northern Pass will grant, or cause to be granted, in favor of HQ Hydro Renewable second priority security interests over all assets and contracts related to the NPT Line and the ownership interests in Northern Pass. HQ Hydro Renewable agrees to subordinate these security interests to Northern Pass's construction debt, any term debt replacing that construction debt and any other debt obtained by Northern Pass to maintain the agreed capital structure.

Article 18 – Dispute Resolution

Initially, disputes are referred to the management committee for confidential resolution. If the dispute cannot be resolved by the management committee, then (a) certain specified matters and any other matters subject to the exclusive jurisdiction of the Commission can be referred to the Commission, (b) technical disputes are referred to a technical arbitrator for confidential resolution in accordance with the International Chamber of Commerce Rules for Expertise, and (c) other disputes are referred to confidential arbitration in accordance with the Rules of the International Chamber of Commerce.

Article 19 – Limitation on Remedies

In addition to specific limitations on remedies contained elsewhere in the TSA, the parties agree to exclude all consequential, special, multiple, exemplary, incidental and

indirect damages of any nature, with certain exceptions for a limited category of direct damages.

Article 20 – Modification of this Agreement

Unless the filing would be inconsistent with the terms and conditions of the TSA, (a) Northern Pass retains the right to make unilateral filings under Section 205 of the Federal Power Act or the regulations thereunder to change the Formula Rate, subject to HQ Hydro Renewable's right to oppose such changes, and (b) HQ Hydro Renewable retains the right to file a complaint under Section 206 of the Federal Power Act seeking to change the Formula Rate. All other amendments of the TSA require the written agreement of both parties and neither party is entitled to make a filing with the Commission that seeks to amend the TSA except as so agreed. The TSA requires that the public interest standard of review be applicable to any modification or amendment of the TSA not mutually agreed by both parties, including any modification or amendment requested by third parties or sought by the Commission, acting *sua sponte*.

Article 21 – Indemnification

Each party agrees to indemnify the other party for third party claims arising out of its gross negligence, willful misconduct or criminal misconduct. HQ Hydro Renewable also agrees to indemnify Northern Pass for the performance of the OASIS provider and OASIS administrator of the capacity release functions and transmission resales. Northern Pass's indemnification obligations exclude claims by affiliates of HQ Hydro Renewable under the TransÉnergie OATT, claims of persons residing in, or arising from events in,

Québec, and claims arising out of a contract between HQ Hydro Renewable and a third person.

Article 22 – Representations and Warranties

Each party makes certain representations and warranties as of specified dates.

Article 23 – Transfer of Interests

Any (a) change in the direct or indirect control of a party, (b) sale or transfer of all or substantially all of a party's assets, or (c) assignment of all or a portion of a party's rights or obligations under the TSA requires the written approval of the other party, not to be unreasonably withheld when viewed in light of all reasonable considerations. If the other party consents to such an event, the security provided by the first party may be terminated or reduced.

The restrictions in Article 23 do not apply to changes of control at the ultimate parent level or to collateral assignments of the TSA to a lender.

Article 24 – Miscellaneous

Article 24 includes agreed miscellaneous provisions, including governing law, notices, confidentiality and waiver of immunities.

Appendix B

Direct Testimony and Exhibits of James A. Muntz

Exh. No. NPT-200

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	**)**	**Docket No. ER11-___-000**

PREPARED DIRECT TESTIMONY AND EXHIBITS OF

JAMES A. MUNTZ

December 15, 2010

EXHIBITS

Exhibit No. NPT-200	Direct Testimony of James A. Muntz
Exhibit No. NPT-201	Maps of NPT Line
Exhibit No. NPT-202	Northern Pass's Application to DOE for Presidential Permit (excluding exhibits)
Exhibit No. NPT-203	Northern Pass's Elective Transmission Upgrade Application (excluding exhibits)
Exhibit No. NPT-204	ISO-NE's August 18, 2009 Letter re: 1,200 MW Transfer Capability
Exhibit No. NPT-205	October 2010 Preliminary Report regarding Economic and Fiscal Impacts of NPT Line
Exhibit No. NPT-206	Excerpts from ISO-NE's 2010 Regional System Plan
Exhibit No. NPT-207	September 2010 Article "Net Greenhouse Gas Emissions at Eastmain 1 Reservoir, Québec Canada"
Exhibit No. NPT-208	Advanced Technology Materials

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTHERN PASS TRANSMISSION LLC) Docket No. ER11-___-000

PREPARED DIRECT TESTIMONY OF JAMES A. MUNTZ

I. INTRODUCTION

Q. Please state your name, business address and position.

A. My name is James A. Muntz. My business address is 107 Selden St., Berlin, Connecticut. I am President of the transmission business of Northeast Utilities' ("NU") operating company subsidiaries and also President of Northern Pass Transmission LLC.

Q. What are your principal areas of responsibility?

A. As the President of the transmission business at Northeast Utilities' operating company subsidiaries, I am responsible for all aspects of the NU transmission system including operations, maintenance, engineering, planning, reliability compliance, project management, and construction.

Q. Please summarize your education and professional qualifications.

A. I graduated from Swarthmore College with a Bachelor of Science degree in Engineering and a Bachelor of Arts degree in Economics. I also earned a

master's degree in Business Administration in Financial Management from Drexel University.

Prior to working at NU, I held various leadership positions with Exelon/PECO in Pennsylvania, including Vice President of Electric Supply and Transmission during the period when deregulation was introduced in that state. In my 22 years with Exelon, I also served as Vice President of its Power Generation Group, Vice President of Nuclear Projects, and held an SRO License on Limerick Units 1 and 2 for over 10 years.

Q. What is the purpose of your testimony?

Northern Pass Transmission LLC ("Northern Pass") seeks Commission approval under Section 205 of the Federal Power Act of a long-term bilateral Transmission Service Agreement ("TSA") between Northern Pass and H.Q. Hydro Renewable Energy, Inc. ("HQ Hydro Renewable") executed on October 4, 2010. The TSA sets forth the terms, conditions, and rates under which HQ Hydro Renewable will acquire firm transmission service over a new ±300-kV high-voltage direct current ("HVDC") transmission line and an associated 345-kV alternating current ("AC") line that will bring 1,200 MW of low carbon, competitively priced energy into New England from Québec.

In my testimony, I will (1) describe the Northern Pass Transmission Line ("NPT Line"); (2) describe the benefits of the NPT Line; (3) describe

ISO New England Inc.'s ("ISO-NE") review of the NPT Line under its regional review process; (4) demonstrate that the NPT Line is not a routine transmission investment and the risks and challenges that the NPT Line faces; and (5) discuss the advanced technologies employed or considered in connection with the NPT Line.

Q. What additional testimony does Northern Pass offer?

A. Five additional witnesses are submitting testimonies in support of this Section 205 filing. Mr. Michael Auseré of NU and Mr. Geoffrey Lubbock of NSTAR provide joint testimony describing the structure of Northern Pass, and the financial risks and challenges that the NPT Line poses to Northern Pass in general, and to NU and NSTAR in particular (Exh. No. NPT-300). Ms. Paula Taupier discusses the formula rate under the TSA (Exh. No. NPT-400). Mr. Timothy Griffin submits testimony regarding Northern Pass's proposed accounting procedures (Exh. No. NPT-500). Dr. William Avera provides testimony to support the reasonableness of the ROE provision set forth in the TSA (Exh. No. NPT-600).

In addition, Charles River Associates ("CRA"), an economic consulting firm, provides a report to demonstrate that the NPT Line will reduce the cost of delivered power in New England by reducing transmission congestion and provide other benefits, including reducing

emissions of greenhouse gases and increasing fuel diversity (Exh. No. NPT-700).

II. DESCRIPTION OF THE NPT LINE

Q. Please describe the NPT Line.

A. The NPT Line is the U.S. portion of the new ±300-kV transmission facility that will interconnect the Hydro-Québec TransÉnergie ("TransÉnergie") transmission system to the ISO-NE administered New England transmission system. This new transmission line will be able to deliver 1,200 MW of Hydro-Québec's low-carbon, predominantly hydro-electric power to New England -- enough to supply approximately one million electric consumers.

TransÉnergie, a division of Hydro-Québec, will develop, construct, own, operate, and maintain the Canadian portion of this new transmission line, extending from the Des Cantons substation in the Province of Québec to the U.S. Border (the "Québec Line"). Northern Pass will develop, construct, own, and maintain the U.S. portion of this transmission tie line -- the NPT Line. Once the NPT Line is commissioned and in commercial operation, ISO-NE will assume operational authority over the NPT Line.

The NPT Line consists of a ±300-kV HVDC above-ground transmission line that extends from the international border to a new direct current to AC converter terminal to be located in the City of Franklin, New

Hampshire ("HVDC Line"). The length of the HVDC Line is approximately 140 miles.

The NPT Line also includes a radial 345-kV transmission line extending from the southern terminus of the HVDC Line in Franklin, New Hampshire to the existing Public Service Company of New Hampshire ("PSNH") Deerfield substation in Deerfield, New Hampshire (the "AC Line") where the project will interconnect with the ISO-NE operated transmission network. The length of the AC Line is approximately 40 miles. Northern Pass will conduct planning studies for ISO-NE to determine the specific design of the AC Line.

The routing of the NPT line will utilize existing PSNH rights-of-way ("ROW") to the maximum extent possible. Currently, it is expected that approximately 50 miles of new ROW will need to be acquired for the HVDC Line. In certain sections of the ROW, existing 115-kV and 34.5-kV structures will be rebuilt in order to efficiently utilize the ROW for the new facilities.

In addition, Northern Pass expects that ISO-NE, as part of its interconnection reliability review under Section I.3.9 of the ISO-NE Transmission, Markets and Services Tariff, may determine that certain additions, upgrades, reinforcements or modifications ("AC Upgrades") to the New England transmission system are necessary to reliably interconnect

the NPT Line, and HQ Hydro Renewable may designate other AC Upgrades identified in the I.3.9 process that it desires to be constructed. The AC Upgrades will be owned and maintained by certain transmission owners (other than Northern Pass but which may include affiliates of NU or NSTAR) that own the existing facilities that are required to be upgraded. Northern Pass will enter into facilities agreements with each transmission owner to pay the costs to engineer, design, permit, construct, and maintain the AC Upgrades.

Additional AC upgrades may also be necessary. In addition to the ISO-NE I.3.9 approval process described above, Northern Pass will request ISO-NE to perform an Overlapping Impact Test. This test will provide a preliminary indication of the level of deliverability of power from the NPT Line, and therefore an indicative assessment of the future capacity value for the 1,200 MW contract on the NPT Line. Certain additional AC system upgrades may be necessary to ensure adequate levels of deliverability. To the extent HQ Hydro Renewable determines that those upgrades are desirable, such upgrades will be treated in a similar manner to the AC Upgrades described above. The final determination of capacity value for the 1,200 MW will occur during the appropriate ISO-NE Forward Capacity Market Auction process.

Maps of the proposed route of the NPT Line are included at Exhibit No. NPT-201. Additional information regarding the NPT Line, including a technical project description, the proposed routing, and environmental impacts, is set forth in Northern Pass's application to the U.S. Department of Energy ("DOE") for a Presidential Permit dated October 14, 2010 (excluding exhibits) (Exh. No. NPT-202).

Q. What is the estimated cost and completion date of the NPT Line?

A. The NPT Line is estimated to cost $1.1 billion, with NU and NSTAR having a 75 percent and 25 percent ownership interest, respectively. Siting of the NPT Line has begun and is expected to continue through 2012 with construction planned to begin in 2013, and a projected in-service date of late 2015.

Q. Given that the new transmission line will be located in both Canada and the United States, how will TransÉnergie and Northern Pass coordinate the design and development of the NPT Line?

A. Northern Pass and TransÉnergie will coordinate the design, development and siting of the Canadian and U.S. portions of the new transmission path in order to efficiently and cost-effectively develop both segments. They have agreed to a structure for jointly coordinating the planning and development of the project that will enable each of their respective project managers who are responsible for overseeing the project and for making

major decisions to work on a cooperative basis to achieve project objectives and milestones.

Q. What initiated the process that led to the development of the NPT Line?

A. New England faces significant energy and environmental challenges. Electricity prices are among the highest in the nation due to a high dependence on fossil fuel. Additionally, new environmental requirements for low carbon, renewable resources will require a significant increase in renewable generation and a change to the region's generation mix. However, even with significant contributions from energy efficiency programs and new, local renewable generation, New England may not be able to meet its future environmental requirements.

Importing hydro-electric power from Canada holds the potential to help meet New England's energy demands and environmental requirements. A portfolio approach, including contributions from additional energy efficiency and demand-side programs, new renewable resources within New England, and import of power from Canada, may help to meet New England's Regional Greenhouse Gas Initiative ("RGGI") requirements.

During the fall of 2007, NU held informal discussions with all of the New England transmission owners and several Canadian generators to

solicit interest in forming an informal collaborative working effort to explore the possibility of importing low carbon, hydro-electric power from Canada. This effort, though initiated by NU, was in line with broader initiatives launched by several regional organizations, including the New England Governor's Conference, the Northeastern International Committee on energy, and the New England Governors/Eastern Canadian Premiers working group on energy. NU first proposed the concept of a new, international transmission line between New Hampshire and Québec in late 2007 at an ISO-NE Planning Advisory Committee meeting focused on HVDC technologies.

Q. What process was used to decide on the specifics of the NPT Line?

A. In the spring of 2008, Hydro-Québec Production submitted a request for service for a new 1,200 MW DC interconnection to New England to Hydro-Québec TransÉnergie. A Working Group comprising representatives from NU and Hydro-Québec TransÉnergie was formed to study the range of alternatives for delivery of 1,200 MW from the Hydro-Québec system to New England. The Working Group evaluated the best method to bring renewable resources into New England. In the fall of 2008, NSTAR became a project partner and joined the Working Group.

The Working Group considered a number of issues, including total NPT Line costs, electrical losses, siting and environmental considerations

as well as system performance. The Working Group studied several basic HVDC alternatives with variations of each alternative.

Q. Why did the Working Group consider only HVDC alternatives?

A. It is necessary to design the NPT Line with DC technology because of the configurations of the Québec and U.S. electrical systems. The Québec electrical system is a separate AC interconnection that operates at a frequency of 60 cycles per second (as does the New England electrical system). However, the Québec system is not operated synchronously with the United States system. This is because of the nature of the types of generation in Québec (large, heavy, slow-rotating hydro machines) relative to the United States (lighter, faster-rotating generation units). It would be difficult to maintain a stable system if they were to operate synchronously. Therefore, the connections between Québec and the United States must be DC connections to act as isolating devices.

Q. After reviewing the various alternatives and HVDC technologies, what did the Working Group conclude?

A. Based upon the analysis that was done, the Working Group identified the preferred option for the delivery of 1,200 MW from the Québec system to New England as being an HVDC line from Des Cantons Substation to a new converter terminal in Franklin, New Hampshire and an associated 345-kV AC line to connect the new Franklin terminal to the existing PSNH 345-

kV transmission system at the Deerfield substation in Deerfield, New Hampshire. This decision was made on the basis of the lowest total cost, an assessment of losses and other key factors such as siting considerations, environmental considerations, and system performance.

Q. Who will have operational authority of the NPT Line?

A. Upon commercial operation of the NPT Line, operational control over the NPT Line will be transferred to ISO-NE pursuant to a Transmission Operation Agreement ("TOA") that Northern Pass will enter into with ISO-NE.

Q. Will the NPT Line be vetted through ISO-NE's stakeholder process?

A. Yes. The NPT Line will be vetted through ISO-NE's stakeholder process under a review procedure appropriate for its status as a participant-funded transmission project. As the Commission recognized in its orders approving NU/NSTAR's Petition for Declaratory Order in FERC Docket No. EL09-20, the NPT Line is a participant-funded transmission project and the NPT Line costs would be paid by HQ Hydro Renewable under the TSA and would not be included in regional rates for transmission service under the ISO-NE Open Access Transmission Tariff. ISO-NE has determined that the NPT Line will be categorized as an elective transmission upgrade. The costs of elective transmission upgrades are not allocated broadly to regional customers. There is no requirement to

demonstrate that elective upgrades are needed to address reliability issues, and they are not subject to any other need or economic benefits analysis under ISO-NE's normal regional planning and approval process. Instead, the NPT Line will be subject only to the ISO-NE Section I.3.9 review process to ensure that it will not have an adverse impact on system reliability and operations.

Q. Please discuss ISO-NE's Section I.3.9 Review Process.

A. The Section I.3.9 process was initiated when Northern Pass filed an elective transmission upgrade application with ISO-NE on October 13, 2010 (*See* Exhibit No. NPT-203), informing ISO-NE of the upgrade's location, size, and how it will integrate with the rest of the ISO-NE transmission system. ISO-NE will review the NPT Line under its I.3.9 process to determine whether the NPT Line has any significant adverse effect on the stability, reliability or operating characteristics of the transmission owner's transmission facilities, the transmission facilities of another transmission owner, or the system of a market participant. A system impact study will be generated as part of that review process, and ISO-NE will be responsible for determining, in consultation with interested parties, whether any system upgrades are needed to interconnect the NPT Line to the regional AC transmission system.

The review process under Section I.3.9 is performed in the first instance by members of two technical task forces of the New England Power Pool ("NEPOOL") Reliability Committee ("RC") -- the NEPOOL Transmission Task Force ("TTF") and Stability Task Force ("STF"). The TTF assists ISO-NE in developing requirements to ensure that New England's bulk electric power system meets established reliability standards. The STF analyzes the dynamic behavior of New England's bulk electric power system as planned and installed. System upgrades may be identified by the TTF and STF to ensure that the project can be interconnected without adverse impacts. After these two task forces are satisfied that the studies demonstrate that the proposed transmission upgrade will not have an adverse impact on the New England power system, the NEPOOL RC, a stakeholder advisory group, reviews the project and provides advisory input to ISO-NE. Following this RC review, ISO-NE takes final action on the elective upgrade application.

ISO-NE's Section I.3.9 review is expected to be completed by mid-2011.

Q. What was the basis for determining the 1,200 MW size of the NPT Line?

A. This determination was based on a combination of the amount of power HQ Hydro Renewable could make available for sale to New England, as well as

the maximum firm transmission capability identified by ISO-NE. In the orders accepting NU/NSTAR's Petition for Declaratory Order, the Commission accepted their offer to conduct an open season in the event that ISO-NE were to determine that the firm transfer capability of the NPT Line could be greater than 1,200 MWs. NU and NSTAR subsequently engaged in discussions with ISO-NE concerning the maximum transfer capability for the NPT Line in order to determine whether NU and NSTAR should hold an open season auction for long-term, firm capacity above 1,200 MWs. As a result of those discussions, on August 18, 2009, ISO-NE notified NU and NSTAR that the maximum long-term, firm transfer capability for the NPT Line would be 1,200 MWs. ISO-NE noted that although "it may be possible to establish some degree of reasonable confidence in the shorter term for source-loss based limits which are higher than 1,200 MWs. . . there is no assurance that a firm capability over 1,200 MWs can be maintained in the long-term frame such as 40 years." (*See* Exh. No. NPT-204).

On the basis of ISO-NE's determination, it became apparent that the NPT Line could not offer long-term transmission service over 1,200 MWs and that no open season was appropriate. Accordingly, NU and NSTAR began moving forward with design and engineering for a 1,200 MW project, including evaluating the impacts of a project of this size on the

New England transmission system. This work is well underway. NU and NSTAR have performed various system planning studies and have conducted preliminary engineering and design of the NPT Line to deliver 1,200 MWs of firm transmission capacity. Further, Northern Pass has submitted its application to the DOE for a Presidential Permit and its elective transmission upgrade application to ISO-NE for technical approval based on a 1,200 MW design.

Q. Why did the design include both a DC line and an AC radial line instead of only a DC line?

A. In addition to economic and technical considerations, the design of the NPT Line was heavily influenced by siting considerations. The initial preference was to build the southern terminus converter station at PSNH's Scobie Pond substation in Londonderry, New Hampshire. Scobie Pond has substantial developable real estate on which to build the converter and is a robust location to interconnect into the 345-kV transmission grid. Losses would have been lower, as well, which could have improved the economics of the project overall. However, a thorough examination of the ROW between PSNH's Deerfield substation and Scobie Pond led us to conclude that the project could not be sited at Scobie Pond. Expansion of that ROW to accommodate the new HVDC line would result in impacts on Land Trust areas, conservation easements, commercial buildings, and up to 50-60

private homes. It was concluded that expansion of the ROW would result in extremely negative public and political reaction against the plan and the overall HVDC project. It was further determined that in order to locate the HVDC converter terminal at Scobie Pond, the ROW would need to be reconfigured with taller structures in order to incorporate the HVDC line and/or the HVDC line would need to be built underground. Either option would have been very expensive and taller structures would have had the additional downside of not being acceptable to the home owners along the ROW.

On a technical basis, the second choice for the location of the DC-AC converter was Deerfield substation where there is a strong interconnection with the 345-kV AC system. Unfortunately, a suitable parcel of land on which to build the converter station could not be located. As a result, the conclusion was that the Franklin area has adequate real estate for the converter station, and with the development of the 345-kV AC direct connect to Deerfield, we could ensure adequate deliverability to make the economics of the project feasible.

III. BENEFITS OF THE NPT LINE

Q. What are the primary benefits of the NPT Line?

A. The NPT Line, combined with the Québec Line, will create a new electric power interconnection that will provide New England electric consumers

with significant access to primarily low carbon and competitively priced generation in Canada, increased reliability, and the ability to achieve certain environmental policy objectives. The energy associated with this surplus capacity is predominantly hydro-electric energy that will dispatch at a low incremental cost, which means that the NPT Line will create the opportunity to lower the overall cost of producing energy to serve New England load. The vast majority of energy delivered by HQ Hydro Renewable over the NPT Line will consist of hydro-electric generation, with the small remainder made up of a combination of other sources of generation.

Q. Will the NPT Line reduce the price of delivered power by reducing transmission congestion?

A. Yes. In its report, CRA evaluated the impact of the NPT Line on New England's wholesale prices, and concluded that the import of 1,200 MW of hydro-electric power to New England over the NPT Line will exert a downward pressure on wholesale power market prices in New England and reduce locational marginal prices.

CRA concluded that the NPT Line will reduce congestion between Québec and ISO-NE by allowing more low-cost energy to be imported in ISO-NE, thus displacing higher cost generation on the ISO-NE system. As a result of this displacement, prices in New England would drop by

approximately $1.58/MWh in 2015, increasing to an average price reduction of approximately $2.30/MWh in 2024. This price reduction would lead to a corresponding drop in the wholesale market cost of supplying New England load, with annual cost reductions of approximately $206 million in 2015, and increasing to $327 million in 2024. These wholesale cost savings would ultimately benefit retail customers through lower electricity rates driven by lower prices in standard offer procurements and lower costs to competitive retail suppliers. *See* CRA Report at §§ 1.2, 2.4, 4 (Appendix G, No. Exh. NPT-700).

Q. Will the NPT Line have reliability benefits?

A. Yes. The NPT Line, combined with the Québec Line, will provide reliability benefits to the bulk transmission system. The NPT Line will increase import capability into New England by 1,200 MW and will provide for an additional inter-regional transmission connection for New England to a region rich in low carbon energy. The NPT Line will improve the efficiency of the electric market(s), allowing the most efficient generation to be utilized over larger portions of the grid and greatly reducing the prospect of congestion. The addition of the NPT Line will provide the New England system with an added degree of reliability in that New England will be able to rely on another 1,200 MW source of power. In effect, the NPT Line looks like another generation source for

New England and is another option for New England in terms of power supply.

The NPT Line also helps set the stage for additional future transmission improvements in New England, and thus added transmission system reliability. The 40-mile AC Line from Franklin to Deerfield extends the existing 345-kV bulk power system further north into New Hampshire. This part of the NPT Line may provide an attractive "jump off" point for additional reliability-based 345-kV upgrades in the future as loads grow. Potential reliability projects enabled by this extension include the addition of autotransformers in Franklin to enhance reliability in that region and further expansion of the 345-kV system to points north or west to meet future reliability needs in either New Hampshire or Vermont.

Q. Please discuss the environmental benefits of the NPT Line.

A. Importing low carbon and renewable hydro-electric power from Québec aligns with environmental policies and goals in New England, including requirements based on New England's participation in RGGI. Hydro Québec has recently completed an independent study of the greenhouse gas emissions from Hydro-Québec's Eastmain 1 complex. The study was conducted over a seven-year period by 80 experts from University of Montreal, McGill University, and Environmental Illimite, Inc. (Exhibit No. NPT-207). The study concluded that hydro-electric power is one of the

lowest greenhouse gas emissions of all generation methods. Specifically, the study concludes that, over the lifetime of the Eastmain 1 complex, greenhouse gas emissions from a northern climate reservoir are expected to be 97.5 percent lower than from a new, gas-fired combined cycle plant. Thus, to the extent that hydro-electric power purchased from Québec displaces gas and other fossil-fired generation in New England, greenhouse gas emissions associated with the production of electricity will be reduced by up to 5 million tons of CO_2 per year, which is equivalent to the annual emissions of nearly 900,000 cars during the term of the TSA. This significant reduction in CO_2 will assist New England in meeting its targets and requirements under the RGGI, which all of the New England states have signed, and under any future cap and trade program or carbon tax adopted at the federal level. The RGGI calls for the New England states to stabilize their CO_2 emissions over the first six years of program implementation (2009-2014) at a level roughly equal to current emissions, before initiating an emissions decline of 2.5 percent per year for the four years 2015 through 2018. This approach will result in a 2018 annual emissions budget that is 10 percent smaller than the initial 2009 annual emissions budget. Current projections show that New England will have a 10 million ton CO_2 compliance gap by 2025 for the RGGI. Low carbon,

hydro-electric power from Hydro-Québec over the NPT Line can potentially cut that gap in half.

Q. What other benefits does the NPT Line provide?

A. Low carbon hydro-electric energy transmitted over the NPT Line will provide fuel diversity benefits that ISO-NE has determined to be essential at this time. In its 2010 Regional System Plan, ISO-NE notes New England's "high dependence on natural gas," and that diversification is necessary because the region continues to depend on natural gas for approximately 40 percent of its electric energy. ISO-NE 2010 RSP, §§ 1.1.4.1, 7.5.6, 13 (Exhibit No. NPT-206). The availability of 1,200 MW of low carbon, renewable hydro-electric energy over the NPT Line will offset this adverse trend. The NPT Line will provide significant fuel diversity for New England, with up to a 20 percent reduction in dependence on natural gas. This, in turn, frees up natural gas for other uses. For example, the "freed up" gas is enough to heat and supply hot water for nearly 1 million homes.

Hydro-electric power is also beneficial as a complement to the other renewable resources that are being considered or are under development in New England, such as wind and solar power, which are intermittent. The NPT Line will make available to New England consumers a substantial source of reliable base load energy. This may defer the need to build fossil

fuel generation plants that would otherwise be required to produce an equivalent quantity of power.

Q. Will the NPT Line produce other economic benefits?

A. Yes. In addition to the benefits described above, the NPT Line will produce significant economic and fiscal benefits to New Hampshire during the construction period and on-going benefits once the NPT Line is in service. According to a preliminary study of the economic and fiscal impact of the NPT Line, this project will create 1,100 to 1,300 quality jobs in New Hampshire per year over the primary construction period 2013 to 2015, which will boost local economies in New Hampshire. The NPT Project will also provide a significant and reliable increase in tax revenue for New Hampshire communities where the NPT Line will be located. *See* "Preliminary Economic and Fiscal Impacts of the Proposed Northern Pass Transmission Project," dated October 2010 (Exhibit No. NPT-205).

IV. THE NPT LINE IS NOT A ROUTINE INVESTMENT

Q. Is the NPT Line a routine transmission project?

A. No. The NPT Line is clearly not a routine or typical utility transmission project. My testimony, together with the testimony of Messrs. Auseré and Lubbock, demonstrates that the NPT Line is a major, large-scale, international project with significant risks and challenges, and that certain TSA rate provisions, if characterized as "incentives" under Order No. 679,

are appropriate and necessary for Northern Pass to proceed with the development and construction of the NPT Line.

Q. Please describe the scope of the NPT Line.

A. The NPT Line will be a new large interconnection between New England and Québec that will provide New England electric consumers with access to 1,200 MW of low carbon, competitively priced hydro-electric energy. The NPT Line will be the largest transmission line project built in New Hampshire since the construction of the existing HVDC line with Hydro-Québec during the late 1980s. The NPT Line will impact 31 cities and towns, require the expansion in some areas of existing ROW, and require the acquisition and development of approximately 50 miles of new ROW. Such a massive undertaking requires not only the support of the public, but the satisfaction of numerous siting and permitting requirements.

In dollar terms, the NPT Line's total cost of about $1.1 billion places it among the largest transmission projects in New England. It will take a six to seven year period that began in 2009 to design, plan, site, permit, engineer and construct the NPT Line.

Q. What risks or challenges does Northern Pass face?

A. In their joint testimony, Messrs. Auseré and Lubbock discuss the financial risks associated with the NPT Line. In addition to those financial risks and

challenges, Northern Pass faces the following additional risks and challenges:

- Siting/Regulatory risks
  - Development of a full environmental impact statement under the National Energy Policy Act
  - Need for a state and federal permits
- Long lead times for equipment procurement
- Risks of cost increases in labor and materials
- Exchange rate risk
- Acquisition of significant property
- System outage sequencing

Q. Please summarize the siting and permitting risks faced by Northern Pass.

A. The construction of any major transmission project requires a significant effort in the areas of siting and permitting. However, the NPT Line faces a number of unique siting and permitting risks. The NPT Line needs to obtain regulatory approvals both in New Hampshire and at the federal level. At the federal level, this involves obtaining a Presidential Permit from the DOE. One or more special use permits from the U.S. Forest Service and the U.S. Fish and Wildlife Service may also be needed. In New England, these are not permitting requirements and risks that are commonly

associated with ordinary, routine transmission upgrades. In addition to increasing the complexity of the processes and requirements that Northern Pass must engage in and satisfy, the additional permitting requirements increase the possibility that federal and state agencies will issue decisions that conflict with one another, an outcome that could delay the project or result in its cancellation.

Further, unlike a routine transmission project or even a large scale single transmission project, the NPT Line is part of a new international transmission tie between New England and Canada, and thus is dependent on the successful siting and approval of the Québec Line.

Q. Please describe the siting/permitting requirements at the federal level.

A. As noted, at the federal level, Northern Pass must obtain a Presidential Permit from the DOE. The DOE is responsible for developing an Environmental Impact Statement ("EIS"), in consultation with other federal agencies, state agencies, and interested parties, pursuant to the requirements of the National Environmental Policy Act. Northern Pass may also need to obtain one or more special use permits from the U.S. Forest Service for those portions of the NPT Line that traverse the White Mountain National Forest and cross the Appalachian Trail, and from the U.S. Fish and Wildlife Service for that portion of the NPT Line that traverses the Pondicherry Division of the Silvio O. Conte Wildlife Refuge. In addition, Northern

Pass must obtain a Section 404 permit from the U.S. Army Corps of Engineers under the Clean Water Act (in consultation with the U.S. Environmental Protection Agency), and approval from the Federal Aviation Administration.

Q. Please describe the siting and permitting issues and risks in New Hampshire.

A. The state permitting requirements include the need to obtain a certificate of site and facility from the New Hampshire Site Evaluation Committee ("NH SEC"). The NH SEC is a state agency designed to provide a single process for obtaining all necessary siting approvals and is comprised of members of various state agencies (including, among others, the New Hampshire Department of Environmental Services, the New Hampshire Public Utilities Commission, the New Hampshire Department of Resources & Economic Development, the New Hampshire Department of Health & Human Services, the New Hampshire Department of Fish & Game, the New Hampshire Department of Cultural Resources, and the New Hampshire Department of Transportation), each of which must review an application to authorize activities that are subject to its jurisdiction and must determine whether or not to approve the application. A decision by a single constituent state agency of the NH SEC to reject an application that is subject to its jurisdiction will result in the NH SEC refusing to issue the

certificate of site and facility. The NH SEC siting process involves consideration of numerous factors, including project solution alternatives, route alternatives, review of wetlands, floodplains and water resources, critical wildlife habitat, threatened or endangered wildlife and plant life, historic and cultural resources, social issues, electric and magnetic fields, engineering designs, and cost review.

In addition, the expansion of existing ROW, and the acquisition of approximately 50 miles of new ROW may, as a last resort, trigger the need to exercise the power of eminent domain in order to achieve that expansion and acquisition. The need to exercise eminent domain authority, which requires approval from the New Hampshire Public Utilities Commission, is not something that is either lightly or easily pursued in any circumstance, and may serve to trigger greater opposition to the project.

Q. What is the anticipated schedule for obtaining siting approval in New Hampshire for the NPT Line?

A. Northern Pass anticipates filing for siting approval for the NPT Line with the NH SEC in late 2011/early 2012.

Q. Are there other risks associated with the NPT Line?

A. Yes. There are several additional risks associated with the NPT Line:

Construction Risk - For approximately 35 of the 140 miles of HVDC ROW, existing 115-kV facilities will need to be rebuilt to make

efficient use of existing ROW. The challenge of constructing two lines in the same ROW, at potentially the same time, requires a significant amount of coordination. Rebuilding certain parts of the existing AC system may also require significant coordination of line outages, something that is made more difficult because few transmission lines exist in the northern portion of the state of New Hampshire. In addition, as the nature and extent of system upgrades required by ISO-NE as a result of the I.3.9 process are currently unknown, the construction of such upgrades and the coordination of outages necessary to achieve that construction are an unquantifiable risk.

Procurement Risk - Due to the current increased demand for transmission-related materials and equipment caused by the number of ongoing upgrade projects throughout the region, the country, and the world, the timely delivery of various materials is a risk to NPT Line costs and schedules. The converter terminal, the most critical component of the NPT Line, has a lead time of approximately three and a half years and will require that contracts be in place long before Northern Pass has received all necessary project approvals. This introduces the risk that the siting processes could change the NPT Line requirements, thereby rendering equipment already purchased inconsistent with the new requirements.

The volatile nature of prices for equipment and services tied to currency fluctuation, competition for limited production capacity and the

raw materials needed to fabricate equipment, creates a risk of cost increases for the NPT Line that could make it uneconomic for HQ Hydro Renewable and allow HQ Hydro Renewable to exercise certain termination rights under the TSA. In addition, difficulty and delay in procuring project equipment and services according to schedule creates a risk that the NPT Line will be cancelled because the desired in-service date cannot be achieved.

Coordination Risk – There are a number of entities involved in the construction of the NPT Line (NU, NSTAR, TransÉnergie, and HQ Hydro Renewable), which could contribute to coordination and management difficulties. The parties will have to be cognizant of outage management and timing delays during construction and will have to work together closely to resolve any issues. Moreover, since portions of the HVDC line will be physically located in both Canada and the United States, the likelihood of coordination difficulties increases. For example, should the Québec Line encounter difficulties with regard to siting and regulation, delays could ensue for the NPT Line.

Project Termination Risk – As discussed in the Auseré/Lubbock testimony, there is the possibility that under certain scenarios (such as cost overruns over certain amounts, the inability to obtain the necessary

regulatory approvals, or a delay in obtaining the necessary regulatory approvals) the NPT Line could be terminated.

Q. What are the risks associated with the NPT Line having a large cost and long development time frame?

A. In general, it means that the NPT Line is more vulnerable to uncertainties associated with changes in cost due to external factors beyond Northern Pass's control. It also means that changes in economic circumstances over time can have very significant impacts on the overall cost and viability of the NPT Line.

Additional delays in the already lengthy and complex process of siting a line can result from public opposition where new ROW needs to be acquired. If a negotiated settlement for property acquisition cannot be reached, eminent domain proceedings may be necessary. In such proceedings, NPT's efforts to secure the ROW for the line may be challenged, resulting in lengthy delays and increased costs. Successful challenges can trigger an entirely new round of planning or, at least, significant modifications to the line route. Should any modification to the line route be made after permits are received, the project would have to re-open siting proceedings to resolve additional issues which will also result in schedule delays. Public opposition can also lead to political or legislative

action such as protective designation of federal or state lands or rivers resulting in regulatory barriers to proposed transmission corridors.

The project will need to comply with and satisfy the environmental requirements of NEPA, and the requirements of the Endangered Species Act and the National Historic Preservation Act in order to obtain approvals from federal agencies with jurisdiction over the NPT Line (such as the U.S. Forest Service and the U.S. Army Corps of Engineers). The process of complying with and satisfying these requirements can also cause extensive delay. The EIS required under NEPA will evaluate the impacts of the NPT Line's proposed route and route alternatives. The evaluation of such alternatives, alternatives which are not yet known, will take time. If, at the conclusion of the EIS and federal permitting processes, one or more agencies conclude that Northern Pass should construct the NPT Line using an alternative route identified as part of the EIS process, Northern Pass may find it is impossible to construct the NPT Line on that alternative route (for example, if the NH SEC rejects that alternative). If one or more state or federal agencies render conflicting decisions in which one agency selects one route while another agency selects a different route, the result would be a regulatory impasse in which the NPT Line could not proceed.

Unanticipated site-specific environmental concerns may arise that lead to the need for additional time-consuming studies, associated

development of mitigation plans, and possible modifications to the scope or route of the NPT Line. Any or all of these factors can significantly affect the construction schedule and greatly increase the associated costs subject to ongoing financing over the course of the NPT Line's construction. These are very real risks that should not be ignored in this proceeding. Major transmission projects are very difficult to site and construct, and that difficulty is increasing, especially as the number and size of projects increase and become more visible.

Q. What other risks are inherent to the NPT Line?

A. HVDC converter terminals are comprised of very high-cost, long-lead time, complex computer-controlled equipment, complex protection control schemes and filtering systems. Use of this technology can lead to extra costs due to delays during testing and commissioning in getting the equipment to operate properly. The planning, engineering, design, operation and maintenance of HVDC converter terminals are complex, requiring special skill sets.

V. ADVANCED TECHNOLOGIES STATEMENT

Q. Does the NPT Line employ advanced transmission technologies?

A. Yes. The NPT Line employs several advanced technologies where appropriate. Specifically, the NPT Line employs the use of HVDC technology, fiber optic cable technologies, high-temperature conductors,

aerial laser survey technology, IEC 61850 Communications Protocols as well as power electronics and related software (including real time monitoring and analytical software). Exhibit No. NPT-208 sets forth further information regarding the advanced transmission technologies in connection with the NPT Line.

Q. Please describe HVDC technology and the conversion from DC to AC.

A. The conversion from DC to AC occurs at a converter terminal. The converter terminal will be designed for a continuous DC to AC transfer rating of 1,200 MW and will utilize DC converter technology (current source converter technology). The converter terminal will be configured as a bipole system and include a dedicated metallic return conductor. The HVDC converter terminal will contain the following equipment and facilities:

- DC Switchyard – The terminal will include a ±300-kV DC switchyard which will be the termination point of the DC line. The DC switchyard will be air insulated and located outdoors.
- DC Filters – The terminal will include DC filters consisting of capacitors, reactors and resistors. The DC filters will be designed to prevent the injection of harmonic currents into the DC transmission system. The DC filters will be air insulated and located outdoors.

- Valve Hall – The terminal will include an electrical enclosure for the thyristor (valves) that will also contain control, protection and monitoring equipment.
- Converter Transformers – The terminal will include oil-filled power transformers with a primary voltage of 345 kV. The ratings of the transformer connection to the valve hall will be determined by the HVDC equipment vendor based on the 1,200 MW transfer rating of the station.
- AC Switchyard – The terminal will include a 345-kV switchyard to interconnect the 345-kV line that will extend to Deerfield Substation. The AC switchyard will be air insulated and located outdoors.
- AC Filters – The terminal will include high voltage AC filters consisting of capacitors, reactors and resistors. The AC filters will be designed to prevent the injection of harmonic currents into the AC transmission system. The AC filters will be air insulated and located outdoors.

Q. Please describe the fiber optic cable technology.

A. In the construction of the NPT Line, an optical ground wire ("OPGW") will be installed throughout the project area. OPGW is installed in the shield wire position, and will act as a standard shield wire protecting the lines from lightning strikes. An OPGW cable is similar to a standard shield wire

but contains a core carrying optical fibers that will be used for communications purposes. The conductive part of the cable serves to bond adjacent towers to earth ground, and shields the high-voltage conductors from lightning strikes. The optical fibers within the cable can be used for high-speed transmission of data, which supports system protection and control, voice communications, and data communications, which is important for emerging smart grid applications.

Q. Please describe the high-temperature conductor technology.

A. In some locations, Northern Pass may employ high-temperature aluminum conductor steel supported ("ACSS") conductor. ACSS conductor is used to increase transfer capability in existing transmission corridors while minimizing the need for major rebuilds. This is possible because ACSS can operate at higher temperatures than conventional aluminum conductor steel reinforced cables. However, ACSS is more expensive to install and if it is operating in its higher temperature range, has much higher losses. As a result, ACSS is being used selectively. NPT is evaluating the use of ACSS conductor for the 345-kV AC line (approximately 40 miles) between the Converter Terminal and Deerfield Substation.

Q. Please describe aerial laser survey technology.

A. Aerial laser survey, sometimes referred to as LIDAR (light detection and ranging), technology has been used extensively in the design of the NPT

Line as an alternative to more costly and time consuming traditional ground survey methods. A scanning laser mounted in a helicopter is used in conjunction with global positioning system satellites to quickly and accurately collect terrain data along a transmission ROW. This data is then incorporated into transmission line design software which can create a 3-D model of the ROW terrain along with existing features on or near the ROW such as structures and conductors of other lines, trees and buildings. The new transmission line can then be electronically modeled taking into consideration conductor type and size, structure configurations, and constraints imposed by terrain, terrain features and other transmission lines occupying the ROW. The use of this technology, with its inherent flexibility to allow quick evaluation of alternative design options, results in a more optimized design at lower cost than traditional methods.

Q. Please describe the IEC 61850 communications protocols.

A. IEC 61850 is a standard defining a new philosophy in substation design, providing secure, cost-effective access to operational and non-operational data through the use of industry proven network communication technology. Similar to today's office networks, where computers, printers and other network devices communicate with each other through the use of "Plug and Play" technology, IEC 61850 brings the capabilities of Ethernet technologies to substations. It provides a client-server architecture

allowing devices from multiple vendors to "talk" to each other via an Ethernet data highway. IEC 61850 defines the standardized language to be used by multiple vendor devices.

One of the immediate benefits afforded by IEC 61850 is reduction of much of the copper control cabling used in the substation. The copper cabling is replaced with fiber optic cables used to communicate via Ethernet between the various devices in the substation (relays, circuit breakers, HMI control/alarm screens, etc.). Remote control and protective relay tripping of substation equipment such as circuit breakers and switches is now communicated to the end device through these fiber optic cables. Another benefit is reduction in the size of relay/control panels and hence the overall footprint of the relay/control building.

Q. Please describe the real time monitoring and analytical software.

A. The construction of the NPT Line will include innovative substation automation packages, including condition monitoring for transformers, which will provide early warning of abnormal conditions and allow the use of a reliability-centered maintenance program that will minimize unnecessary maintenance outages. This technology will be employed for the converter terminal transformers of the NPT Line. Specifically, the terminal will employ advanced condition monitoring equipment that will

provide for the remote archiving and viewing of non-operational data for the following equipment:

- Transformers and reactors will be equipped with an integrated monitor and control system that provides on-line indication of cooling system parameters and dynamic, real time electrical load characteristics in respect to design ratings of the transformer.

- Additional monitoring of the transformers' physical condition will be accomplished by the addition of automated Dissolved Gas Analyzers ("DGAs"). These DGAs will provide a daily report on the condition of the transformers' and shunt reactors' internal insulation status. Monitoring trends, in a relative wide spectrum of gasses, can indicate a number of possible impending problems requiring repairs or monitoring on an increased frequency.

Q. Does this complete your testimony?

A. Yes.

Exhibit No. NPT-201

Maps of the NPT Line

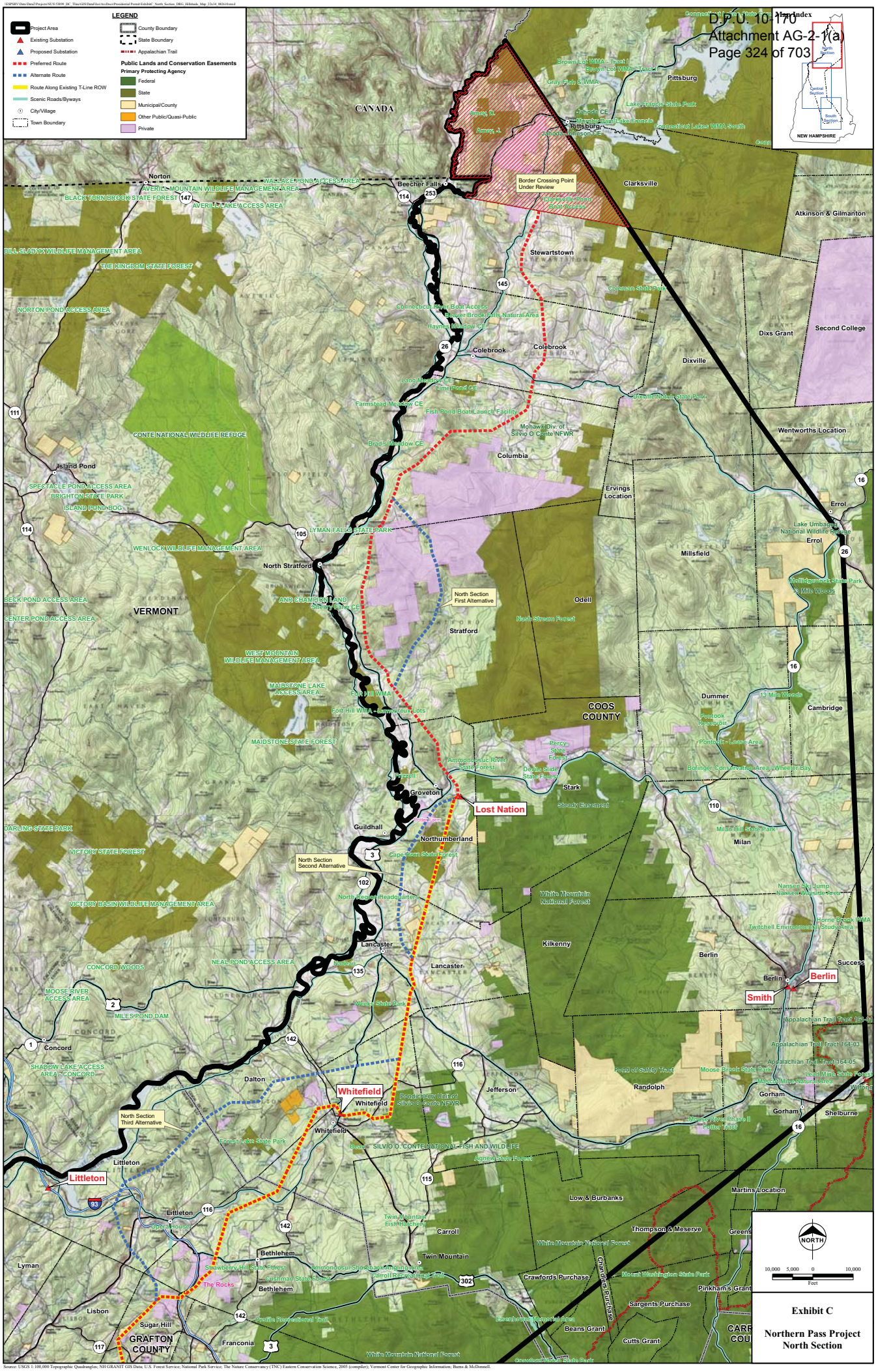


Exhibit C

Northern Pass Project
North Section

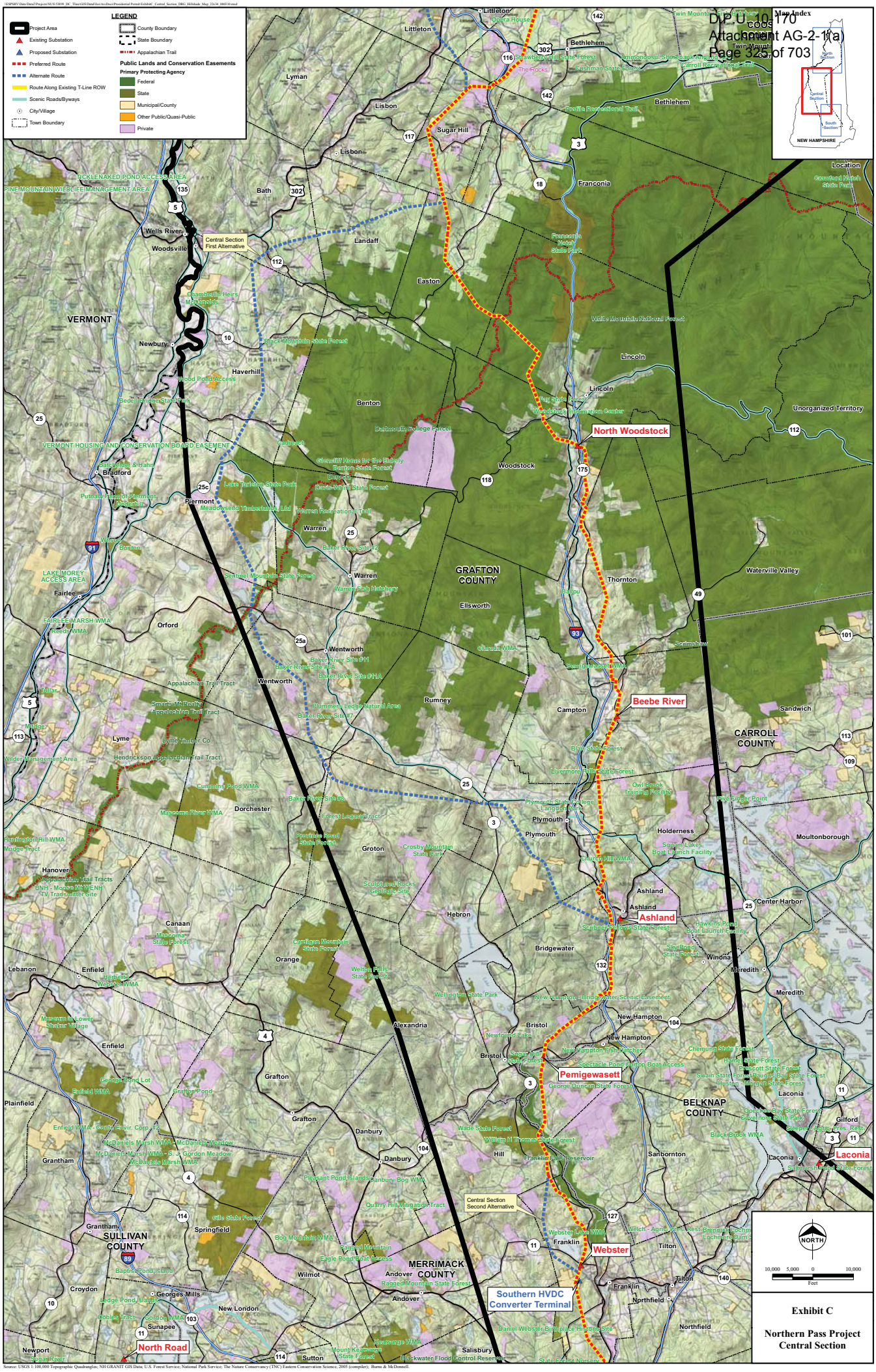
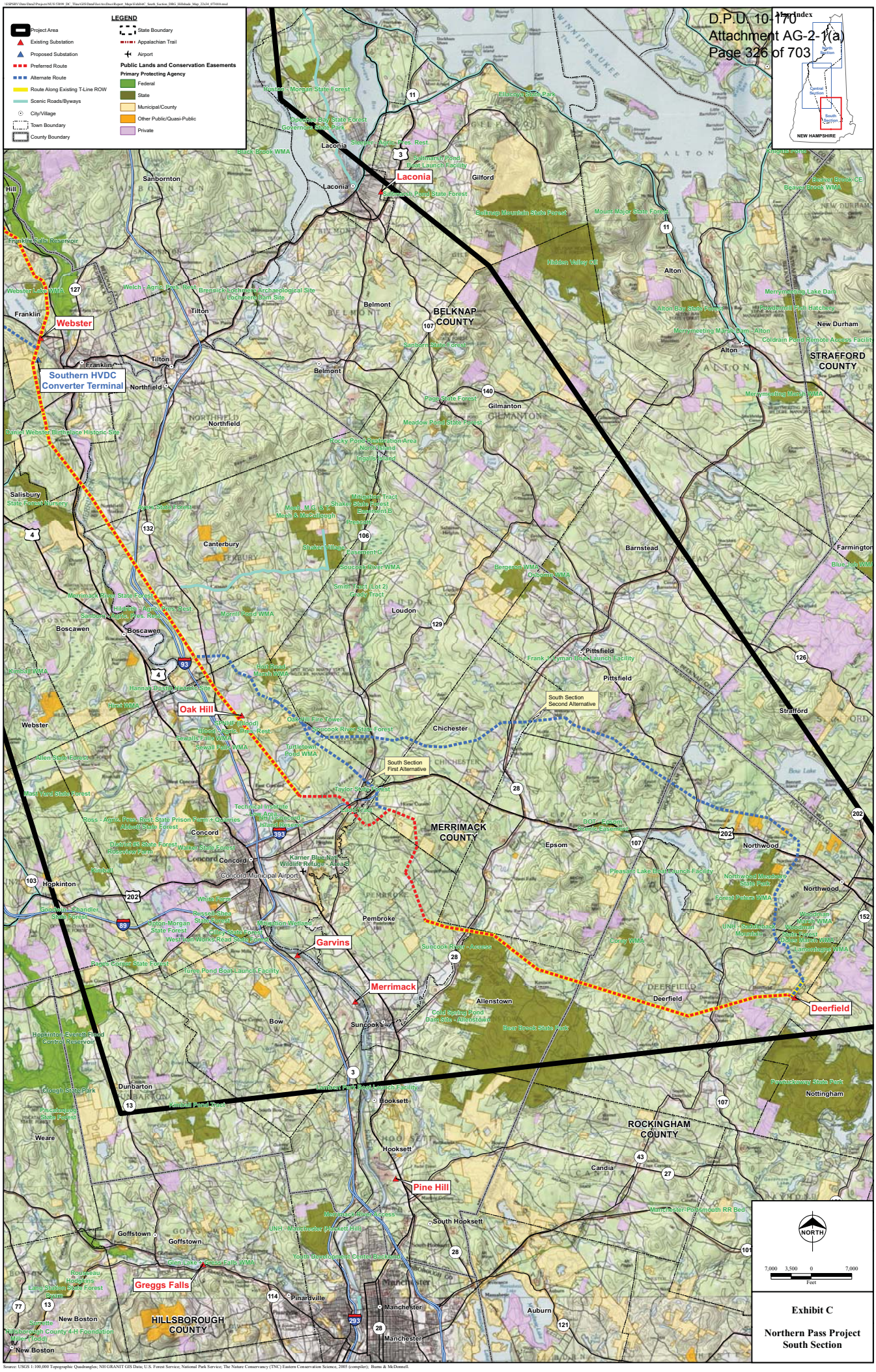


Exhibit C

Northern Pass Project
Central Section

Source: USGS 1:100,000 Topographic Quadrangles; NH GRANIT GIS Data; U.S. Forest Service; National Park Service; The Nature Conservancy (TNC) Eastern Conservation Science, 2005 (compiler); Burns & McDonnell.



Source: USGS 1:100,000 Topographic Quadrangles; NH GRANIT GIS Data; U.S. Forest Service; National Park Service; The Nature Conservancy (TNC) Eastern Conservation Science, 2005 (compiler); Burns & McDonnell.

Exhibit C

Northern Pass Project
South Section

Exhibit No. NPT-202

Northern Pass's Application to DOE for Presidential Permit
(Excluding Exhibits and Attachments)

UNITED STATES OF AMERICA
BEFORE THE
DEPARTMENT OF ENERGY
OFFICE OF ELECTRICITY DELIVERY AND
ENERGY RELIABILITY

NORTHERN PASS TRANSMISSION LLC

DOCKET NO. PP-___

APPLICATION OF
NORTHERN PASS TRANSMISSION LLC
FOR PRESIDENTIAL PERMIT

OCTOBER 14, 2010

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Exhibit A Opinion of Counsel
Exhibit B Drawing of Typical Structure Configurations
Exhibit C General Area Map – Preferred and Alternative Routes
Exhibit D Area Map of Border Crossing
Exhibit E System Power Flow Plots (to be provided later)
Exhibit F Verification of Application

APPLICATION

Pursuant to Executive Order (EO) No. 10485, as amended by EO 12038, and 10 C.F.R. § 205.320 *et seq*., Northern Pass Transmission LLC (Northern Pass or the Applicant) hereby applies to the United States Department of Energy (DOE) for a Presidential Permit authorizing the construction, connection, operation, and maintenance of facilities for the transmission of electric energy at the international border between the United States and Canada. This Application does not seek authority for any export of power from the United States. The information that follows is submitted in support of the Application.

SECTION 1

INFORMATION REGARDING THE APPLICANT

Northern Pass is a special purpose entity created to construct, own, operate and maintain a transmission project (the Project) that will deliver competitively priced, low carbon power[1] that will help satisfy the requirements of the Regional Greenhouse Gas Initiative (RGGI) by reducing greenhouse gas emissions, help achieve the goals of the New Hampshire Climate Action Plan by enabling importation of Canadian hydroelectric power, and help mitigate price volatility in the region's energy market by increasing the region's fuel diversity. It will achieve these goals by capitalizing on Hydro-Québec's excess capacity from hydro-electric generating facilities that already exist or are currently under construction and by enabling the flow of approximately 1,200 MW of power into New Hampshire and the New England region. The Project will be participant-funded by H.Q. Hydro Renewable Energy, Inc., an indirect, wholly-owned U.S. subsidiary of Hydro-Québec, under a Transmission Service Agreement (TSA) that is subject to approval by the Federal Energy Regulatory Commission (FERC). The power that flows as a result of this Project will be competitively priced, and it will not be intermittent in the way that wind and solar power are. The Project will also serve to meet future load growth requirements,

[1] The electricity delivered by H.Q. Hydro Renewable Energy, Inc. over the Project would consist of "system" power comprised of approximately 98% hydroelectric generation, with the balance made up of a combination of other sources of generation.

and it may help avoid or defer the need to construct fossil fuel generation plants that would otherwise be required to produce an equivalent quantity of reliable power.

1.1 Legal Name of the Applicant

The legal name of the Applicant is Northern Pass Transmission LLC. Northern Pass has its principal place of business at Energy Park, 780 North Commercial Street, Manchester, NH 03101.

1.2 Legal Names of All Partners

Northern Pass is jointly owned by NU Transmission Ventures, Inc. (75 % owner), a wholly-owned subsidiary of Northeast Utilities, a publicly held public utility holding company, and NSTAR Transmission Ventures, Inc. (25% owner), a wholly-owned subsidiary of NSTAR, a publicly held public utility holding company. NU Transmission Ventures, Inc. and Northeast Utilities both have their principal place of business at 56 Prospect Street, Hartford, CT 06103. NSTAR Transmission Ventures, Inc. and NSTAR both have their principal place of business at One NSTAR Way, Westwood, MA 02090.

1.3 Communications and Correspondence

All communications and correspondence regarding this Application should be addressed to the following persons:

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Northeast Utilities
107 Selden Street.
Berlin, CT 06037
860-665-2771
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Washington, DC 20004
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maryanne.sullivan@hoganlovells.com

1.4 Foreign Ownership and Affiliations

Neither Northern Pass, NU Transmission Ventures, Inc., nor NSTAR Transmission Ventures Inc., nor their respective ultimate parent entities, is owned wholly or in part by a foreign government or any instrumentality thereof. Northern Pass will have an undivided ownership of the Project facilities on the U.S. side of the border.

The high voltage direct current (HVDC) facilities located on the Canadian side of the border will be owned and operated by Hydro-Québec TransÉnergie, a division of Hydro-Québec. Additionally, Northern Pass has executed a TSA with H.Q. Hydro Renewable Energy, Inc., an indirect, wholly-owned U.S. subsidiary of Hydro-Québec. Once approved by FERC, the TSA will allocate 1,200 MW of transmission capacity over the Project to H.Q. Hydro Renewable Energy, Inc. on the U.S. side of the border in exchange for transmission service payments that cover the costs of, and investment in, the Project.

1.5 Existing Contracts with Foreign Entities for Purchase, Sale or Delivery of Electric Energy

As noted above, Northern Pass has executed a TSA with H.Q. Hydro Renewable Energy, Inc. Northern Pass has no other direct or indirect contracts for purchase, sale, or delivery of electric energy with any foreign or foreign-owned entities.

1.6 Corporate Authority and Compliance with Laws

Exhibit A is an opinion of counsel stating that the construction, connection, operation, and maintenance of the proposed facility is within the corporate power of the Applicant and that the Applicant has complied with and, if the proposed actions are performed in accordance with this Application, will comply with all pertinent federal and state laws.

SECTION 2

INFORMATION REGARDING THE TRANSMISSION LINES TO BE COVERED BY THE PRESIDENTIAL PERMIT

2.1 Project Overview

Northern Pass proposes to construct an HVDC electric transmission line with a bidirectional 1,200 MW transfer rating running from the international border between New Hampshire and Canada to Franklin, New Hampshire, where it would connect with a 345 kV alternating current (AC) line. The northern HVDC converter terminal will be constructed at the Des Cantons Substation in Québec, Canada, and will be connected to a HVDC line that will run southward in Québec for approximately 45 miles where it will cross the Canada / US border into New Hampshire. The New Hampshire segment of the HVDC line will continue southward for approximately 140 miles to the southern HVDC converter terminal. The southern HVDC converter terminal will be constructed in Franklin, New Hampshire, and will convert the direct current (DC) power to AC power. Northern Pass proposes to construct the 345 kV AC line from the Franklin converter terminal location to the Deerfield Substation in Deerfield, New Hampshire owned by Public Service Company of New Hampshire (PSNH), a wholly-owned subsidiary of Northeast Utilities.

The Project will enable the bidirectional transmission of 1,200 MWs of power between Québec to New England, providing low carbon, competitively priced electricity for consumers in the New England region. Once the Project has completed commissioning and is ready for commercial operation, the Independent System Operator - New England Inc. (ISO-NE) will assume operational control over the Project pursuant to the terms of a FERC-approved Transmission Operating Agreement between Northern Pass and ISO-NE.

In addition to its energy benefits, the Project will bring significant economic and fiscal benefits to New Hampshire during its construction phase, and on-going benefits once the Project is operational. Based on preliminary estimates, hundreds of direct construction jobs in New

Hampshire, as well as professional and technical services jobs, will be supported during the Project's construction phase. Through the multiplier effects from the direct and indirect expenditures, additional economic activity in retail, services, and other sectors is also expected, in total adding tens of millions of dollars to household earnings each year during the construction phase. Once the Project is operational, it will significantly add to the tax base for both the state of New Hampshire and the municipalities in which the facilities will be built.

2.2 Technical Description

2.2.1. Number of Circuits[2]

For the portion of the Project running from the international border to Franklin, New Hampshire, Northern Pass proposes to construct a single circuit ±300 kV HVDC above-ground transmission line that will be mounted on structures ranging from approximately 90 feet to 135 feet tall. The length of the HVDC portion of the Project is approximately 140 miles.

For the AC portion of the Project, Northern Pass proposes to construct a single circuit 345 kV AC above-ground transmission facility running from Franklin to Deerfield, New Hampshire. Planning studies that Northern Pass is conducting for ISO-NE will determine the ultimate configuration of that transmission facility. Northern Pass proposes to construct the 345 kV AC line mounted on structures ranging from approximately 80 feet to135 feet tall. The length of the AC portion of the Project is approximately 40 miles.

Typical existing right-of-way (ROW) widths for the Project vary from approximately 150[3] to 410 feet.

2.2.2. Operating Voltage and Frequency

The nominal operating voltage for the HVDC line will be ±300 kV and will consist of positive energized conductors, negative energized conductors and a dedicated metallic return conductor. The nominal operating voltage for the AC facility will be 345 kV, three-phase at a frequency of 60 Hz.

[2] In certain areas, existing 34.5 kV and 115 kV structures will need to be rebuilt (within the existing ROW) in order to efficiently utilize existing ROW for the new facilities.
[3] An exception to this 150 foot width exists along a 1/4 mile distance within the White Mountain National Forest where the ROW width is set at 100 feet under an existing Special Use Permit.

2.2.3. Conductors

The choice of the specific conductors that will be utilized for the HVDC line is being evaluated. One alternative being evaluated is an "Aluminum Conductor Steel Reinforced" (ACSR) conductor. It would have a designation of 2156 kcmil ACSR "Bluebird," which has an outside diameter of 1.76 inches. Rated breaking strength of this conductor is 60,300 pounds. The proposed design would limit the tension in this conductor to 16,000 pounds under the National Electric Safety Code (NESC) heavy district loading. For this type of conductor, there would be a three conductor bundle for each energized positive or negative energized conductor and one dedicated metallic return conductor.

Another alternative being evaluated is one that would reduce the number of conductors required in each conductor bundle from three to two. This alternative is an "All-Aluminum Alloy Concentric-Lay-Stranded" (AAAC) conductor. It would have a designation of 2932.9 kcmil AAAC which has an outside diameter of 1.975 inches. Rated breaking strength of this conductor is 83,500 pounds. The proposed design would limit the tension in this conductor to approximately 23,000 pounds under the NESC heavy district loading. For this alternative, there would still be a requirement of one 2932.9 kcmil AAAC conductor for installation as the dedicated metallic return.

The 345 kV AC type of conductor proposed is an ACSR conductor that has the designation of 1590 kcmil ACSR "Lapwing." It has an outside diameter of 1.50 inches. Rated breaking strength of this conductor is 42,200 pounds. The proposed design would limit the tension in this conductor to 11,400 pounds under the NESC heavy district loading. The 345 kV line will use a two-conductor bundle for each energized phase.

Additional conductors for the AC and DC circuits may be evaluated during the design process before the conductor selection is finalized.

2.2.4. Additional Information Regarding Overhead Lines

i. Wind/Ice Loading

Wind and ice loading for the proposed design incorporates three NESC loading cases required for this area of the Unites States. These cases are Rule 250B, Rule 250C and Rule 250D. Rule 250B is the NESC heavy district loading case. It consists of a wind velocity of 40 mph, 0.5 inch of ice and a wire temperature of 0ºF. This is the only loading case that requires an additional NESC constant of 0.3 lb/ft. The constant is applied to every foot of conductor. Rule 250C considers extreme wind. A wind velocity of 100 mph at 60ºF is the weather condition applied during this case. Rule 250D is a loading case that considers wind and ice. It contains a wind velocity of 40 mph, 1 inch of ice and a wire temperature of 15ºF.

In addition to the loading conditions required by the NESC, the proposed design will incorporate an additional combined wind and ice loading case to address icing conditions present in New Hampshire. That case consists of a wind velocity of 40 mph, 1.25 inches of ice and a wire temperature of 15ºF.

ii. Description of Typical Supporting Structure

Northern Pass is evaluating the supporting structure type(s) and configurations shown in Exhibit B for use in the Project. The general structure details provided below are typical of such supporting structures.

Because terrain and existing ROW width along the preferred route varies, two structure types are being considered for the HVDC line: tubular steel (monopole) and steel lattice structures. For both the monopole and lattice structures, a configuration where the energized conductors are oriented horizontally in relation to one another and a configuration where the energized conductors are located vertically in relation to one another will be required. For both the monopole and lattice configuration, the horizontally configured structures would be approximately 90 feet in height, and the vertically configured structures would be approximately

135 feet in height.[4] The monopole configurations would be approximately five to ten feet in diameter at the base, tapering to approximately one to two feet in diameter at the top. These structures would be anchored to a concrete foundation approximately seven to twelve feet in diameter. The lattice configuration will have an approximate base dimension of 30 by 30 feet and taper to a six by five foot column half way up the structure. Lattice structures will be anchored to four concrete foundations at the corners of the base approximately three to five feet in diameter.

The arms of the structures will support an insulator string, the bundled conductors and a dedicated metallic return conductor. Horizontally configured structures will support two overhead static ground wires where the vertically configured structures will support only one. In each case, one of the overhead static ground wires will have a fiber optic core to enable communications and system protection functions between the two converter stations.

For the 345 kV AC portion of this Project, multiple structure configurations will be used to accommodate the variety of existing ROW width and conditions. In ROW areas that can accept a wider horizontal configuration, the 345 kV transmission line will be installed on wood or steel H-frame structures and will be approximately 80 feet in height. These structures will consist of two wood or steel poles with a 26 foot separation. Pole diameters for these structures will be approximately one to three feet. Foundations for these structures will involve direct embedding of a portion of the pole in the ground. The cross-arm of this structure will support all three insulator strings and the energized conductors. In addition, these structures will support two overhead static ground wires. One of the overhead static ground wires will have a fiber optic core for communications and system protection functions between the Franklin converter terminal and Deerfield Substation.

In areas with narrower ROW width (due to constraints that limit ROW expansion), steel monopole structures in delta (two conductors on one side of the monopole and one conductor on the opposite side) and vertical configurations can be used. In addition, some areas may require

[4] Structure heights are typical for a straight, level stretch of land. Actual structure heights will vary, and may be greater in height (e.g., highway crossings), based on topography, span length and the line layout.

double circuit configurations (two circuits installed on a common structure). Structure heights for these configurations range from approximately 110 feet to 130 feet with a base diameter of approximately five to ten feet, tapering to one to two feet at the top. These structures will be anchored to a concrete foundation approximately seven to twelve feet in diameter. The arms of the structures will support an insulator string and the energized conductors. In addition, these structures will support one or two overhead static ground wires depending on the specific structure configuration. One of the overhead static ground wires will have a fiber optic core for communication and system protection functions between the Franklin converter terminal and Deerfield Substation.

iii. Structure Spacing

In areas where the new line will be located in existing ROW, structures will run in parallel to the existing transmission line structures along ROW's that generally range from 150 to 410 feet in width. Some of these existing ROW's may need to be expanded to make room for the new transmission line, and some existing transmission lines may need to be reconfigured to do the same. In areas where the new line will be located on all new ROW, support structures will be placed in ROW that is approximately 150 feet wide. Generally, structures will be spaced approximately 800 feet apart with a maximum spacing of approximately 1,000 feet.

iv. Conductor Spacing

The Project will employ horizontal and vertical spacing between ±300 kV HVDC energized conductors of 26 feet. For 345 kV energized conductors, the horizontal spacing will be 26 feet and the vertical spacing will be 22 feet.

v. Line to Ground and Conductor Side Clearances

For HVDC clearances, the horizontal distance between each energized conductor and the support structure will be approximately 15 feet. Minimum ground clearance for the conductors will be 30 feet. Energized conductors will be attached to the structure using 20 DC type insulator disks

per string. This will provide approximately 10 feet of insulation between the energized conductors and the arm of the structure.

For the AC 345 kV circuit, the horizontal distance between an energized phase and the support structure will be approximately 13 to 15 feet. Minimum ground clearance for conductors will be 24 feet. Energized phases will be attached to the structure using 17 insulator disks per string. This will provide approximately eight feet of insulation between energized phases and the arm of the structure.

vi. Underground and Underwater Lines

The Project will not employ underground or underwater lines.

vii HVDC Southern Converter Terminal

The conversion from DC to AC occurs at a converter terminal. The converter terminal will be designed for a continuous DC to AC transfer rating of 1,200 MW and will utilize conventional DC converter technology (current source converter technology). The converter terminal will be configured as a bipole system and include a dedicated metallic return conductor. The HVDC converter terminal will contain the following equipment and facilities:

- Valve Hall – The terminal will include an electrical enclosure for the thyristor (valves) that will also contain control, protection and monitoring equipment.
- Converter Transformers – The terminal will include oil-filled power transformers with a primary voltage of 345 kV. The ratings of the transformer connection to the valve hall will be determined by the HVDC equipment vendor based on the 1,200 MW transfer rating of the station. The transformers will be located outdoors.
- AC Switchyard – The terminal will include a 345 kV switchyard to interconnect the 345 kV line that will extend to Deerfield Substation. The AC switchyard will be air insulated and located outdoors.
- AC Filters – The terminal will include high voltage AC filters consisting of capacitors, reactors and resistors. The AC filters will be designed to prevent the injection of

harmonic currents into the AC transmission system. The AC filters will be air insulated and located outdoors.

- DC Switchyard – The terminal will include a ±300 kV DC switchyard which will be the termination point of the DC line. The DC switchyard will be air insulated and located outdoors.
- DC Filters – The terminal will include DC filters consisting of capacitor, reactors and resistors. The DC filters will be designed to prevent the injection of harmonic currents into the DC transmission system. The DC filters will be air insulated and located outdoors.

2.2.5. AC System Interconnection

The Project's interconnection to the New England electrical system will be at the existing PSNH's Deerfield Substation located in Deerfield, New Hampshire. The 345 kV line from the converter terminal will terminate at a new position on the substation breaker and a half bus. New substation equipment to support the interconnection consists of terminal structures, 345 kV switches, breakers, bus work, instrument transformers and associated protection and control devices. No expansion to the existing substation area is needed to support the new line position.

2.3 General Area Map and Border Area Maps

Exhibit C contains general area maps (north, central, south sections) showing the approximate locations of the Project facilities.

A map that shows the general area where the Project will cross the international border is attached as Exhibit D. A detailed map showing the exact latitude and longitude of the border crossing will be provided as soon as practicable after Northern Pass and Hydro-Québec TransÉnergie each complete consultation processes with interested stakeholders which will provide input for the border crossing decision.

2.4 Bulk Power System Information

2.4.1. Expected Power Transfer Capability

The Project's rated power transfer capability between the Québec and the New England transmission systems is approximately 1,200 MW. Based on available vendor estimates, the Project's short term overload capability is expected to be in the range of 10% to 15%. The actual short term overload capability will be determined in the detailed engineering design phase.

2.4.2. System Power Flow

Northern Pass recognizes that DOE regulations require it to provide system power flow plots for the Applicant's proposed service areas for heavy summer and light spring load periods, with and without the proposed international interconnection, for the year the line is scheduled to be placed in service and for the fifth year thereafter. Northern Pass is currently conducting system studies of the transmission network as administered by ISO-NE. After the completion of these studies, which we expect to occur in early 2011, Northern Pass will promptly provide DOE with the required system power flow plots.

2.4.3. Interference Reduction Data

Electrical interference associated with the HVDC line has been analyzed for the conductor configurations indentified in Section 2.2.3. Radio interference is generated by corona occurring on the conductors. The conductor and DC voltage selected for this line results in a relatively low level of corona, which in turn avoids any unacceptable level of radio interference.

Electrical interference from a HVDC line in terms of television interference is a result of gap type discharges. The design of this HVDC line will use modern hardware, appropriate construction techniques and a line configuration that yields a low level of corona that will minimize the onset of gap discharges which in turn avoids any unacceptable level of television interference.

Interference issues associated with the 345 kV line are being addressed using the Project design standards. Based on that analysis, the conductor size, tension of the line and distance to other lines and to the edge of the ROW will be designed to minimize electrical interference issues.

Electrical interference of the converter terminal is also being addressed using the Project design standards. Equipment spacing and minimum conductor size requirements designed to minimize electrical interference issues have been identified. Additional details regarding the features required to minimize interference effects of the converter station will be developed during the Project's detailed design phase.

2.4.4. Relay Protection

The HVDC converter terminal protective relaying systems will utilize microprocessor based devices that conform to Northeast Utilities, Institute for Electrical and Electronics Engineers, North American Electric Reliability Corporation and Northeast Power Coordinating Council requirements. Specific protection schemes, equipment and functional devices will be determined during the Project's detailed design phase, which is expected to be complete in 2012.

SECTION 3

INFORMATION REGARDING ENVIRONMENTAL IMPACTS

3.1 Introduction

The Project will provide clean, low carbon, competitively priced and reliable hydroelectric power from Québec to consumers in the adjacent State of New Hampshire and the New England region. Much of the transmission facility is proposed to follow existing transmission line ROW's in order to avoid or minimize environmental impacts. In addition, in the siting of any new ROW's, structures and facilities, Northern Pass will seek to avoid, minimize, and/or mitigate environmental impacts while still meeting the construction, performance, and reliability needs of the Project.

Northern Pass anticipates that DOE will prepare an Environmental Impact Statement (EIS) to assess the environmental impacts of the Project, in compliance with the National Environmental Policy Act (NEPA) and DOE's implementing regulations, 10 CFR Part 1021.

Northern Pass further anticipates that the environmental impacts associated with the Project will be reviewed by numerous agencies and the public during preparation of the EIS and during the federal and state permitting processes. Topics likely to be addressed include land use and infrastructure; geology and soils; engineering; hazardous materials; electric and magnetic fields; water resources; wetlands and floodplains; vegetation; wildlife; fish; rare, threatened and endangered species; air quality and climate change; noise; socioeconomics; cultural (archeological, historical, etc.) resources; visual resources; and electric system operation and reliability.

3.2 Assessment of Environmental Impacts

In order to be better prepared for the permitting process and to develop information to support the Project design effort, Northern Pass undertook a preliminary assessment of the potential environmental impacts of the Project, including the impacts on both natural and cultural resources, some of which is reflected in the discussion that follows. Northern Pass anticipates that the information presented here regarding environmental and cultural resource issues will be refined, expanded and updated through DOE's NEPA review and the federal/state permitting process.

The effort to develop a preferred route for the Project began with the establishment of a project area. The boundaries of the project area were established based on the need to (i) locate a transmission line crossing at the border between Québec and New Hampshire, and (ii) connect into the AC system grid at a location that allows for the delivery of 1,200 MW. Power flow studies were used to identify the DC facility end point in Franklin, and the AC terminal location at the existing Deerfield Substation.

After establishing the project area, the next step was to collect data on human and natural resources and to identify possible engineering constraints and obstacles. Project representatives obtained that data by meeting with state and federal natural resource agencies, non-governmental organizations (stakeholder groups), and by examining publicly available information databases. Primary sources of data were color aerial photography, field identification of residences, businesses and public facilities, and geographic information system (GIS) data from various state and local agencies. The GIS data included federal and state lands, conservation easements, historic and archaeological resources, parks, rivers, and other resources. Most of the data were quantified using GIS software; others were calculated by measuring information directly from the aerial photography.

Using GIS software, all of this information was incorporated into maps of the project area so that the locations of known constraints, such as publicly or privately held conservation areas, could be identified and taken into consideration. Once the constraint maps had been developed, the

process of identifying potential routes for the HVDC and AC transmission lines began. The objective was to identify routes that began at the border between Canada and New Hampshire, extended to the converter terminal location in Franklin and continued to the Deerfield Substation while avoiding or minimizing impacts to both human and natural resources.

Route segments were then laid out within the project area to create hundreds of potential route variations, avoiding known constraints, to the extent possible, and taking advantage of opportunities to follow existing linear facilities such as transmission line corridors, roads, and railroads where the Project could share existing ROW. The potential routes consisted of individual segments that could be combined to form a continuous path between endpoints. This step included consideration of multiple alternatives through each section of the project area. A first level review of these initial alternatives resulted in the elimination or modification of some alternatives because of either potential impacts to human or natural resources, or engineering difficulties such as steep slopes.

Northern Pass then conducted a second level review in which it quantified the social and environmental resources that would be impacted by the remaining route alternatives. This evaluation of the routes included a systematic comparison of the alternatives based on criteria that represented the potential adverse effects on resources along the route segments based on the types of resources present. The quantitative data were totaled for all of the potential routes. These data were used in evaluating the remaining alternatives, through the application of a mathematical comparison of the routes, to identify the routes with the least overall social and environmental impact.

The segment alternatives were divided into three geographic sections for the analysis:

- The north section, consisted of 46 segments which can be combined into 528 possible routes and are located between the Canadian border and Whitefield Substation, in Whitefield , New Hampshire, utilizing both existing and new ROW;

- The central section, which consisted of six segments and four possible routes and includes both a route that traverses the White Mountain National Forest (WMNF) on existing ROW, and a route that goes around the WMNF on new ROW; and

- The south section, which consisted of 37 segments and 32 possible routes that are located from the Franklin southern terminal location to the existing Deerfield Substation utilizing both existing and new ROW.

Northern Pass then reviewed all of the data obtained from the mathematical comparison (statistical analysis) of the routes. The result was the selection of a preferred route and certain alternative route segments for the proposed transmission facility. Northern Pass believes that, as a general matter, the impacts of the preferred route will have less impact on environmental and other resources than the alternative route segments. The preliminary assessment of environmental impacts that follows is for this preferred route, and Northern Pass describes generally how those impacts would differ if other alternatives were selected.

3.2.1 Wetlands, Floodplains and Water Resources

The minimization of impacts to rivers, streams, lakes, ponds, floodplains and wetlands crossed by the Project was a critical objective in Northern Pass's selection of a preferred route. The Project will cross several large rivers, many ephemeral, intermittent and perennial streams and ponds. New state stream-crossing rules will apply to all streams and rivers that must be crossed by equipment. State law provides special protection to certain water bodies including Public Waters, Designated Rivers, fourth order and larger streams, and streams within the WMNF. All rivers and streams in the WMNF have been designated as "Outstanding Resource Waters" (ORW) by the New Hampshire Department of Environmental Services (NHDES).

Based on National Wetland Inventory (NWI) data, Northern Pass estimates that approximately 5.5 miles of wetlands would be traversed by the Project's preferred route. However, Northern Pass also recognizes that NWI maps may underestimate the quantity of forested wetlands, which are the most common wetland type in New Hampshire. Northern Pass anticipates that a detailed analysis of flood plain and wetland impacts will occur during DOE's NEPA review based on field delineation of wetlands along the preferred route using state and federal protocols and consultation of Federal Emergency Management Agency Flood Insurance Rate Maps.

3.2.2 Critical Wildlife Habitat

Neither the Project's preferred route nor the alternatives would cross land that the United States Fish and Wildlife Service (USFWS) has designated as critical habitat for any endangered species. There currently is no designated critical habitat for any species in the State of New Hampshire.

3.2.3 Threatened or Endangered Wildlife or Plant Life

The USFWS New England Field Office database lists the eastern cougar, Indiana bat, grey wolf, dwarf wedgemussel, and the Karner blue butterfly as federal endangered animal species with ranges that encompass portions of the preferred and/or alternative routes. A portion of the preferred route passes through Coos County where the Canada lynx is potentially present. In addition to these wildlife species, the USFWS also lists the Jesup's milk-vetch and Robbin's cinquefoil as endangered plant species and the small whorled pogonia as a threatened plant species with ranges known to encompass the preferred and/or alternative routes (USFWS, 2009).

In New Hampshire, the Nongame and Endangered Wildlife Program of the Fish and Game Department is the steward for the state's nongame wildlife, that is, species that are not hunted, fished or trapped. The New Hampshire Natural Heritage Bureau (NHB) in the Division of Forests and Lands at the Department of Resources and Economic Development is responsible for identifying, tracking and protecting New Hampshire's rare plants and exemplary natural communities. The NHB maintains a comprehensive data base of threatened and endangered species throughout New Hampshire.

Based on data from the NHB, there are no records of federal threatened or endangered species occurring within 1,000 feet of the preferred and/or alternative routes. The NHB data, however, include records of state listed species occurring within 1,000 feet of the Project's preferred and/or alternative routes. State endangered species are the northern harrier, wild comfrey, and golden fruited sedge at the northern section of the preferred route, and the muskflower in the central portion of the alternative route. State threatened species are the Kalm's lobelia at the

northern portion of the preferred route, the peregrine falcon and Pickering's bluejoint (plant) at the central section of the alternative and preferred routes, respectively, and the state northern black racer (snake) in the southern portion of the preferred route, and wild lupine in the southern portion of an alternative route. Additionally, the NHB database includes records that do not identify the species present at the recorded location due to the species' vulnerability to illegal collection. There are five such records within 1,000 feet of the alternative routes and one such record within 1,000 feet of the preferred route.

Northern Pass will coordinate with the USFWS, U.S. Forest Service (USFS), U.S. Environmental Protection Agency, New Hampshire Department of Fish and Game, New Hampshire Department of Resources and Economic Development, NHDES and scientists from research institutions and environmental organizations and others to ensure that potential impacts to threatened and endangered species and habitats have been carefully considered and avoided, minimized or mitigated.

3.2.4 Navigable Waterway Crossing

The Connecticut River is designated a federal navigable river in New Hampshire from the Massachusetts Border, north to Pittsburg. The preferred route would cross the Connecticut River once in the Town of Pittsburg. The Merrimack River is also considered a federal navigable waterway south of Concord to the Massachusetts-New Hampshire state line. The AC line would cross the Merrimack River north of Concord, where it is not designated a navigable waterway.

3.2.5. Indian Land

There is no federally-designated Indian land in the areas along either the preferred route or the alternative routes. Northern Pass will follow the guidance of the New Hampshire Division of Historical Resources (DHR)/State Historic Preservation Office and the USFS regarding cultural resource assessments and consultations with Tribes that may have historical interests' affected by the Project.

3.2.6 Federal Lands

The preferred route crosses two major federal natural resource areas, the WMNF and the Appalachian National Scenic Trail (Appalachian Trail or AT). The preferred route crosses approximately 10 miles of the WMNF, all on an existing transmission line ROW. Northern Pass proposes to construct the new line largely within this existing ROW. A large part of the Appalachian Trail in New Hampshire runs through the WMNF. The preferred route crosses the AT within the WMNF on the existing transmission corridor described above. The policies of both the USFS and the National Park Service (NPS) specify that any new crossings of these lands should be at already disturbed locations, and the preferred route is consistent with both of those policies. One alternative, as described below, would go around the WMNF. It is 13 miles longer than the preferred route, requires acquisition and clearing of a new 53 mile long, 150 foot wide ROW, and would cross the AT at a location that does not currently contain a transmission line crossing, although it is a "disturbed location" in that it would cross the AT at a highway.

Northern Pass intends to engage the USFS, NPS, the Appalachian Trail Conservancy and the Appalachian Mountain Club and other stakeholder groups with regard to the proposed AT crossing, so that their concerns and requirements can be considered early in the Project evaluation and design.

3.3 Historic and Cultural Resources

Based on information obtained from the DHR, ten historic sites have been identified within a half-mile of the Project's preferred route that are listed on the National Register of Historic Places or are eligible for listing. These sites include the Poore Family Homestead District and Keazer-Flanders Farm in Stewartstown, the Johnson Farm in Stratford, the Rocks Estate in Bethlehem, the Campton Town House near Beebe River in the Town of Campton, Hill Center Church in the Town of Hill, the Aiken Family Webster Lake Complex on Webster Lake in the City of Franklin, the Webster Farm Historic District in the City of Franklin, the Stone Arch Culvert in the Town of Canterbury, and the Deerfield Center Historic District in the Town of Deerfield. Northern Pass anticipates that, in cooperation with DOE, it will support further

research and field studies for the Project and coordinate with the State Historic Preservation Office during the NEPA and federal and state permitting processes, consistent with Section 106 of the National Historic Preservation Act.

3.4 Right of Way, Operations & Maintenance

To the extent possible, Northern Pass intends to use existing transmission ROW under an arrangement with PSNH. Regardless of the final routing, Northern Pass anticipates the need to acquire some additional ROW. From the international border crossing location to the Lost Nation Substation, located in the Town of Northumberland, New Hampshire, a distance of approximately 45 miles, no transmission ROW exists, and new ROW that will be 150 feet wide must be acquired. The 150-foot width for the new ROW is based on the clearance requirements of the Northern Pass design criteria which, in turn, are derived from, and consistent with, the NESC. From Lost Nation Substation to the HVDC converter terminal in Franklin, the new line will be located within an existing transmission ROW, although in some areas this ROW will have to be expanded. In addition, in some areas, existing AC transmission and distribution lines will have to be relocated or reconfigured within the ROW to make the most efficient use of existing ROW.

The 345 kV AC facility from the converter station in Franklin to the Deerfield substation will use existing ROW where possible. In some areas where the ROW is not wide enough, the ROW area will need to be expanded. In areas where ROW expansion is not possible because of congestion or constraint, new ROW will need to be acquired.

Northern Pass will also acquire temporary easements during the construction process to accommodate construction activities (e.g., access and lay down areas).

Maintenance of the lines will be performed in accordance with Northeast Utilities system maintenance policies and procedures, the elements of which are to:

- Identify industry best practices for a specific preventative maintenance program;

- Assure compliance with regulatory and power coordination authority standards and guidelines;
- Establish maintenance practices that are practical and cost effective;
- Establish maintenance practices that monitor equipment operating conditions and provide trendable data; and
- Provide a written description of the maintenance program.

Specific requirements for high voltage transmission lines include:

- Aerial patrol of lines each year for inspection of structures and conductor;
- Foot patrol of the lines each year to visually inspect the facilities;
- Thermographic inspection of lines two times per year;
- Patrol of lines after every operation (i.e., permanent or temporary line faults) if the specific cause cannot be identified;
- Aerial patrol of lines each year for vegetation management inspection; and
- Three year vegetation trimming cycle.

Maintenance activities in the ROW, depending on the natural features and accessibility of the ROW, can be carried out on foot, or by line truck, track mounted vehicle, ATV or snowmobile. Any of these activities can have an impact on the environment if not performed in a sensitive manner. All vegetation management and line maintenance activities associated with the Project's new lines will be performed in accordance with the New Hampshire Division of Forest and Lands Best Management Practice for Utility Maintenance (Interim, January 2010). That Best Management Practice provides guidance for identifying appropriate means and methods for vegetation management and maintenance in or within the vicinity of jurisdictional wetlands. Northern Pass will provide a field manual summarizing the Best Management Practice to all contractors performing maintenance work in the ROW.

Maintenance associated with the HVDC converter terminal and the Deerfield Substation upgrades will also be performed in accordance with Northeast Utilities system maintenance policies and procedures, the elements of which are to:

- Monitor, test and maintain civil, electrical, protection and communication equipment including visual inspection, sampling, trending, testing, maintenance and time based equipment replacement; and
- Monitor on-line key electrical devices to determine equipment status, load levels, temperature and to identify any abnormal conditions.

SECTION 4

ALTERNATIVES TO THE PROPOSED FACILITY

The selection of a preferred route was the product of a very deliberate process through which Northern Pass carefully evaluated the potential environmental, historical and cultural resource impacts of a wide variety of alternative routes. It is a route that, in the judgment of Northern Pass, would minimize these impacts. The analysis described in Section 3.2 resulted in the identification of multiple alternative segments rather than completely separate routes because the beginning, intermediate and end points of the Project are necessarily fixed by three key factors: the desire to avoid or minimize impacts by using existing electric transmission system ROW to the extent feasible; the configuration and design limits of the existing electric transmission system; and the purpose and need for the Project. Many route segments were eliminated from consideration because of the adverse impacts on environmental, historical or cultural resources or because they are technically infeasible.

Specifically, Northern Pass has evaluated routing alternatives that it is capable of constructing and operating, that avoid and minimize environmental and cultural impacts, that are technically feasible, and that satisfy the underlying purpose and need of the Project of providing the capacity to deliver power from Des Cantons Substation in Quebec to southern New Hampshire. Within those constraints, there are a number of routing alternatives that Northern Pass believes it is capable of implementing, that would meet the Project's objectives, and that could be selected by permitting agencies if, in particular circumstances, the impacts of an alternative are deemed by such agencies to be more acceptable than those along the preferred route.

Therefore, the preferred route represents Northern Pass' best judgment in selecting a route from a wide range of alternatives – all of which are banded both by the practicable limits of what Northern Pass is capable of doing and by the need to satisfy the Project's objectives. The maps attached as Exhibit C show three alternative segments for the north section, two alternative segments for the central section, and two alternative segments for the south section. Generally, the alternatives offer trade-offs between the types of resources affected.

4.1 Alternatives in the North Section

Three alternative segments were identified in the north section. The first alternative is 0.5 miles longer than the preferred route and is located east of the preferred route primarily in the Town of Stratford, New Hampshire. This alternative is approximately 10.2 miles long and deviates to the east around several mountains to limit its visibility from the Connecticut River Scenic Byway. However, this alternative would cross part of the Bunnell Working Forest, a protected conservation area.

The second alternative segment is approximately 8.6 miles long, 1 mile longer than the preferred route, and it would bypass the Cape Horn State Forest to the west and traverse the towns of Northumberland and Lancaster. This alternative traverses fewer wetlands and water bodies, but it does not follow existing ROW and would be more visible from the Connecticut River Scenic Byway. This alternative also traverses the Potter Farm, a privately-owned conservation area.

The third alternative segment is approximately 21.1 miles long, 1.8 miles longer than the preferred route, and it would bypass the community of Whitefield, as well as an historic site and some conservation lands. However, this alternative would require acquisition and development of all new ROW over its entire length. This alternative would also be more visible from, and would cross, the Connecticut River Scenic Byway.

4.2 Alternatives in the Central Section

Two alternative segments were identified in the central section. The first alternative winds around the WMNF and is approximately 53 miles long. It is 13.3 miles longer than the preferred route and requires acquisition and clearing of a new 53 mile long, 150-foot wide ROW. In addition, this alternative would cross the AT at a location that does not currently contain a transmission line crossing. This would be contrary to the NPS's stated policy goal of utilizing a "like" crossing for new transmission facilities.

The second alternative segment leaves the existing ROW just north of Webster Lake and goes around the west side of the lake for 5.3 miles before rejoining the existing ROW south of the Webster Substation. This alternative is .1 mile longer than the preferred route, would locate the line in new ROW, and would be highly visible to the residents around Webster Lake.

4.3 Alternatives in the South Section[5]

Two alternative segments were identified in the south section. The first alternative, which would leave the existing ROW north of Oak Hill Substation, is 8.8 miles long, 0.5 mile shorter than the preferred route, but it requires 5.2 miles more of new ROW than the preferred route. This alternative also has 33 more newly affected residences than the preferred route.

The second alternative segment also leaves the existing ROW north of Oak Hill Substation and runs in an easterly direction until it connects to an existing distribution line corridor. This 28.3-mile alternative is 1.7 miles longer than the preferred route, requires expansion of approximately 9.7 miles of existing distribution ROW and acquisition of 18.6 miles of new ROW, 10.6 miles more new ROW than is required for the preferred route. The alternative also has 37 more newly affected residences than the preferred route.

4.4 No Action Alternative

The no action alternative of not constructing the Project would eliminate the Project's direct impacts to environmental, historical and cultural resources in the area along the preferred route.[6] However, that would be at the expense of losing the Project's capacity for delivering 1,200 MW of clean, low-carbon power and achieving the policy objective of improving fuel diversity. In addition to helping achieve these environmental and energy policy goals, the injection of such

[5] Northern Pass may conclude that one additional segment represents a feasible alternative route. Provided ISO-NE approves the proposed configuration of the 345 kV AC line, and provided that the Federal Aviation Administration authorizes the location of the necessary transmission structures in the vicinity of Concord Municipal Airport, that alternative route would follow existing ROW for approximately 7.7 miles in the City of Concord and the Town of Pembroke, NH. This route is not depicted on Exhibit C.

[6] Note, however, that, if and to the extent impacts in Canada are a factor, the no action alternative would not result in the cancellation, or delay in construction, of any hydroelectric generation facilities in Canada.

reliable, renewable and competitively priced power would help to meet the New England region's future load growth needs, and help mitigate energy market volatility which is often driven by the price of fossil fuel-based sources of power. If the Project were not constructed, the need to reduce greenhouse gas emissions to help meet RGGI requirements would still exist, as would the need to develop sources of cleaner, low carbon, renewable power and the need to reduce our reliance on fossil fuel. To achieve those objectives, other transmission lines that would likely have environmental, historical and cultural resources impacts of the same character and magnitude as those created by the Project would need to be built to deliver that power.

Additionally, without this Project's capacity to bring Hydro-Québec's excess hydro-electricity to the U.S., in order to satisfy future load growth and provide the same level of service from non-intermittent power sources, new power plants would need to be built that would almost certainly have greater impacts on environmental and other resources than the Project will have. In summary, as a practical matter the no action alternative does not really serve to avoid impacts; it will only result in the similar and potentially more significant impacts to environmental, historical and cultural resources. Based on the Project's combination of characteristics and benefits, the no action alternative is a poor option.

SECTION 5

VERIFICATION

Exhibit F contains a verification of the contents of this Application by an officer of Northern Pass having knowledge of the matters set forth herein.

Exhibit No. NPT-203

Northern Pass's October 13, 2010 Elective Transmission Upgrade Application
(Excluding Exhibits)

THE NORTHERN PASS℠

Northeast Utilities Service Company
P.O. Box 270
Hartford, CT 06141-0270
(860) 665-3315
Fax (860) 665-6717
Email: muntzja@nu.com

James A. Muntz
President – Northern Pass Transmission

October 13, 2010

Mr. David Forrest
ISO-New England
One Sullivan Road
Holyoke, MA 01040-2841

Dear Dave,

Northern Pass Transmission, LLC (NPT) is pleased to submit this Elective Transmission Upgrade application to ISO-NE under Section II.47.5 of the ISO New England Inc. Transmission, Markets and Services Tariff for our proposed 1200 MW HVDC transmission interconnection between Québec, Canada and New Hampshire.

NPT, which includes Northeast Utilities and NSTAR, has been working collaboratively with Hydro-Québec to design this project and complete the commercial agreements necessary to make it a reality. The NPT project will provide a new international interconnection for New England and allow for the import of significant amounts of economically priced, low carbon energy that will help the region in meeting its environmental requirements for CO2 reductions.

NPT looks forward to working with ISO-NE on this important project for New England. If you have any questions, or require additional information please do not hesitate to call.

Very truly yours,

James A. Muntz

JAM:dsf

Elective Upgrade Application

The undersigned Elective Transmission Upgrade Applicant submits this application to interconnect an Elective Transmission Upgrade to the PTF or Non-PTF under Section II.47.5 of the ISO New England Inc. Transmission, Markets and Services Tariff (the "Tariff").

PROJECT INFORMATION

Proposed Project Name: Northern Pass Transmission Project

Description of the Elective Transmission Upgrade, including the location of the upgrade (County(ies) and State(s)), any affected Transmission Owners, and the purpose of the upgrade. If known, describe equipment to be used (e.g. overhead line, underground line, phase shifting transformer, etc.), rating of the equipment (e.g. MW, MVAR, kV, etc.) and proposed operation of the upgrade.

The Northern Pass Transmission (NPT) Project includes a new HVDC interconnection from the Province of Québec to south-central New Hampshire. The NPT Project will provide a new international interconnection for New England and allow for the import of significant amounts of economically priced, low carbon energy that will help the region in meeting its environmental requirements for CO2 reductions. This new Project is designed to deliver 1200 MW of power at an operating voltage of ± 300kV DC. It is expected to be completed in 2015, assuming timely review of state and federal permitting applications. The Canadian segment of the DC line will connect to the 230-kV system in Québec at the Des Cantons Substation where the northern HVDC converter terminal will be located. The HVDC line will run southward in Québec for approximately 45 miles where it will cross the Canada / US border into New Hampshire. The New Hampshire segment of the DC line will continue southward for approximately 140 miles to the southern HVDC converter terminal in the City of Franklin, New Hampshire. The HVDC converters are expected to use conventional HVDC technology and the line will be a bipolar design and use overhead construction. The HVDC segment of the Project is expected to locate facilities within Coos, Grafton and Merrimack counties in New Hampshire. This

segment of the Project is expected to use existing Public Service Company of New Hampshire (PSNH) rights-of-way (ROW) wherever feasible. New ROW will need to be acquired where no existing transmission ROW exists (north of the existing PSNH Lost Nation substation to the Canadian border), where the existing ROW needs to be expanded to accommodate the HVDC line, locations where expanding the ROW is not possible due to existing constraints or where state or federal permitting agencies order deviation from existing ROWs.

NPT will also require certain 345-kV AC facilities to be added to the New England bulk power transmission grid in order to connect the new HVDC terminal to the 345-kV bulk power transmission grid. These will include a new, radial 345-kV circuit from the HVDC converter terminal in Franklin, NH to the existing PSNH Deerfield Substation in Deerfield, NH. This segment of the Project will locate facilities in Merrimack and Rockingham counties in New Hampshire. The AC facilities will also use overhead construction and include any necessary substation and terminal additions at Deerfield and Franklin substations as well as any additional system upgrades that may be required as a result of the ISO-NE technical project review process.

Approximate location of the proposed Point(s) of Interconnection (information is not required as part of the initial Interconnection Request):

Consistent with the design described above, the point of interconnection will be the Deerfield Substation in Deerfield, NH.

Projected Commercial Operations Date: 2015.

A detailed map (2 copies), such as a map of the quality produced by the U.S. Geological Survey, which clearly indicates the site of the new facility and pertinent surrounding structures is attached (check one):

__X__ Yes
_____ No

See Attachment A.

A one-line diagram (2 copies) of the new facility (check one):

__X__ Yes
_____ No

See Attachment B.

The ISO will post the Project Information on the ISO web site on OASIS and at:
http://www.iso-ne.com/genrtion_resrcs/nwgen_inter/status/index.html

APPLICANT INFORMATION

Company Name: Northern Pass Transmission, LLC
(Elective Transmission Upgrade Applicant)

Company Address: **PO Box No.:** **PO Box 270**

Street Address: _____

City, State ZIP: **Hartford, CT 06141-0270**

Company Representative: **Name: James A. Muntz**

Title: President – Northern Pass Transmission LLC

Company Representative's Company and Address (if different from above):

Company Name: _____

PO Box No.: _____

Street Address: _____

City, State ZIP: _____

Phone: (860) 665-3315 **FAX: (860) 665-6717** **E-mail: muntzja@nu.com**

This Elective Transmission Upgrade Application is submitted by:

Authorized Signature: _____

Name (type or print): **James A. Muntz**_____

Title: **President – Northern Pass Transmission**_____

Date: **October 13, 2010**_____

In order for an Elective Transmission Upgrade Application to be considered a valid request, it must:

(a) Be accompanied by a non-refundable administrative fee of $2,500.00; and
(b) Include all information required on the Elective Transmission Upgrade Application form.

Failure to provide the above items and all the information required on the application could result in delaying the processing of your application.

FAX or Mail To: **ISO New England Inc.** **1 Sullivan Road**
FAX: **413-540-4203** **Holyoke, MA**
01040-2841
Attention: **Dave Forrest** **Phone: 413-540-4584**

ISO New England Inc. Use

Date Elective Transmission Upgrade Request Received: _____ **Received By:**_____

☐ **Administrative Fee Deficient** **Date Cured:** _____

☐ **Application Deficient** **Date Cured:** _____

Date Deemed Valid Application: _____ **Deemed Valid By:** _____

Exhibit No. NPT-204

ISO-NE's August 18, 2009 Letter

Stephen J. Rourke
Vice President, System Planning

August 18, 2009

James A. Muntz
President – Transmission
Northeast Utilities Service Company
P.O. Box 270
Hartford, CT 06141-0270

Geoffrey Lubbock
Vice President
NSTAR Electric Company
One NSTAR Way
Westwood, MA 02090

Re: Proposed HVDC Line from Québec to New Hampshire: Operating Limits Above 1,200 MW

Gentlemen:

I am writing in response to your July 28, 2009 request for written clarification regarding the operating limits that ISO New England ("ISO-NE") would place on the Available Transfer Capability ("ATC") of the HVDC line from Québec to New Hampshire (the "Project") proposed by Northeast Utilities Service Company ("NUSCO"), NSTAR Electric Company ("NSTAR"), and Hydro-Québec Energy Services (U.S.) ("HQUS"). This Project was discussed with representatives of ISO-NE at a meeting on July 6, 2009 at ISO-NE offices. Based on our discussions at the July 6 meeting and in your July 28 letter, it is our understanding that the Project proponents are seeking to determine the level of transmission service which would not be subject to reduction pursuant to normal operating protocol in order to determine the amount of firm transmission service that could be made available by the Project.

As we discussed at the July 6 meeting, pursuant to the normal operating protocol that has been filed with the FERC, it has been established that, nominally, the low limit for a source-loss contingency in New England is 1,200 MW. However, based on operating experience, there may be many hours during which the allowable source loss may be greater than 1,200 MW, depending on prevailing system conditions in NY and in PJM. Conversely, unusual system conditions in New England, New York or PJM could potentially result in source-loss limits which could reduce to levels below 1,200 MW. Therefore, conditioned upon all facilities being initially in service, a long-term firm transfer capability of 1,200 MW is reasonable based on allowable source loss.

It may be possible to establish some degree of reasonable confidence in the shorter term for source-loss based limits which are higher than 1,200 MW. As you may be aware, ISO-NE, with the appropriate advisory input from regional stakeholders, established a 1,400 MW capacity value for the

ISO New England Inc.
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www.iso-ne.com T 413 535 4306 F 413 540 4203

Phase II HVDC line for the first, second, and third Forward Capacity Auctions. Recent operating experience supported the determination to use 1,400 MW in the Forward Capacity Market; however, there is no assurance that a firm capability over 1,200 MW can be maintained in a long-term time frame such as the 40 years suggested in your July 28 letter.

Hopefully this provides the clarification that you have been seeking. Please do not hesitate to contact me or Rich Kowalski (413.535.4127) for additional information or to discuss this further.

Sincerely,

Stephen J. Rourke
Vice President, System Planning

cc: D. Gates
M. Gonzalez
B. Kay
R. Kowalski
T. Paradise

Exhibit No. NPT-205

October 2010 Preliminary Report Re: Economic and Fiscal Impacts of the NPT Line

Preliminary Economic and Fiscal Impacts of the Proposed Northern Pass Transmission Project

Prepared for
Northern Pass Transmission LLC

Prepared by
Dr. Lisa Shapiro
Chief Economist
and
Heidi Kroll
Policy Analyst
Gallagher, Callahan & Gartrell, P.C.
www.gcglaw.com

Gallagher, Callahan & Gartrell PC

October 2010

Gallagher, Callahan & Gartrell PC

Summary

The Northern Pass transmission project is a proposal for a transmission line to bring 1,200 MW of competitively priced, low carbon, renewable energy (predominantly hydropower) from Canada into the Northeast region. HQ Hydro Renewable Energy, Northeast Utilities, and NSTAR are partnering on the proposed Northern Pass Transmission project, and have received preliminary approvals from the Federal Energy Regulatory Commission on the proposed funding model. The Northern Pass transmission project is proposed to be located in about 30 communities in New Hampshire, where it will interconnect system power, primarily from hydro sources into the regional power grid. The project is still in the design, engineering, and business deal phase. Federal permitting processes are expected to begin this fall, and state permitting in late 2011.

The preliminary conceptual cost estimate for the Northern Pass transmission project proposal is $1.1 billion. It would involve a major New Hampshire construction project over the projected primary construction period of 2013 – 2015, subject to all regulatory approvals. Upon completion, this new utility property would add to the taxable property base in over 30 communities, several counties, and the state. The purpose of this report is to provide preliminary estimates of the economic impacts to New Hampshire during the development and construction phases of the project, and the property tax payments to local communities, counties, and the State of New Hampshire from the project when operational. Results of this analysis are summarized below and covered in more detail in this report.

- Summary of Preliminary Estimates -
Economic and Fiscal Impacts of Proposed Northern Pass Transmission Project
New Hampshire

Development and Construction Phase

- New Hampshire Employment – Annual Average 2013–2015, 1,100 – 1,300 Jobs
- New Hampshire Household Earnings – Cumulative 2010–2015, $204-$249 Million
- New Hampshire Economic Output – Cumulative 2010–2015, $259-$316 Million

See Pages 3 – 5 for more detail.

Operational Phase

Annual Property Tax Payments in New Hampshire – TOTAL: $15 to $20 Million

- Local - $9–12 Million
- State - $5–6 Million
- County - $1–2 Million

See Pages 5 – 6 for more detail.

Background

The Northern Pass transmission project is a proposal for a transmission line to bring 1,200 MW of competitively priced, low carbon, renewable power (predominantly hydropower) into the region in order to meet carbon emissions reduction goals (as separate and distinct from renewable portfolio standard requirements). HQ Hydro Renewable Energy, Northeast Utilities, and NSTAR are partnering on the proposed Northern Pass Transmission project, and have received preliminary approval from the Federal Energy Regulatory Commission (FERC) on the participant funded model for the project. This novel funding model means that only those that purchase power will pay for the cost of the transmission line, through a bundled rate that includes the energy charge and the cost of the line at a competitive rate.[1]

Work to develop alternative siting routes is underway, with the permitting processes to begin this fall and into 2012. Approximately 180 miles of transmission line, a converter terminal and substations would be constructed in New Hampshire. The primary construction phase is currently targeted for 2013 through 2015, subject to all regulatory approvals.

The preliminary conceptual cost estimate for the project is $1.1 billion. The purpose of this Report is to provide preliminary estimates of the economic impacts to New Hampshire during the development and construction phases of the project, and the fiscal impacts from property tax revenues once the project is in-service.

The estimates developed are by definition preliminary as they rely on conceptual cost estimates, regional and industry average allocations for local versus non-local labor and materials budgets, assumptions about job types and average wages, and simple static multipliers (RIMS II). This report is being prepared in order to provide a first order approximation of the economic impacts of a $1.1 billion transmission construction project on employment, output, and household earnings in New Hampshire. When more refined cost estimates and siting routes are available, a more detailed economic impact analysis could be conducted to update these preliminary estimates.

For the fiscal impact analysis on New Hampshire communities, estimated annual property tax payments were developed using a range of assumptions on property tax rates and budget levels for municipalities, counties, and the state.

[1] Federal Energy Regulatory Commission Order Granting Petition for Declaratory Order, Docket No. EL09-20-000, Issued May 22, 2009.

Estimated Economic Impacts from Construction

The proposed Northern Pass transmission project is a major construction project and would be one of the largest energy infrastructure projects in recent New Hampshire history. A large transmission construction project utilizes in-state contractors and workers as well as out-of-state specialized contractors and workers. Competitive bidding is utilized for many subcontracts. This preliminary report relies on industry and regional average allocations: about one-third of the total direct expenditures are assumed to be made to New Hampshire workers and firms for these preliminary estimates. It is expected that there will be extensive New Hampshire jobs related to clearing and site work, harvesting, construction and materials, including electrical, professional, and technical services.

New Hampshire specific multipliers from the federal government's Regional Input-Output Modeling System (RIMS II [2]) were then applied to the preliminary estimates of the direct expenditures in New Hampshire for materials and labor during the development and construction phase of the proposal to develop the total economic impacts in New Hampshire.

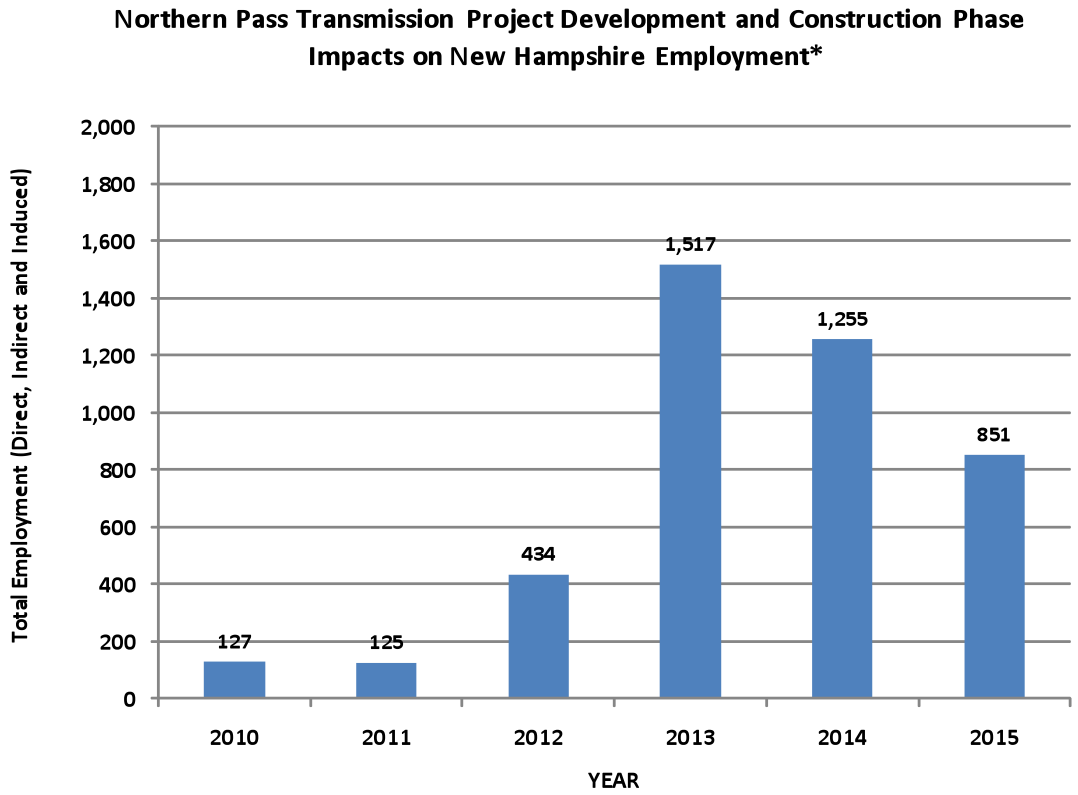
Preliminary estimates are that the project will positively impact in-state employment by an average of 1,100 – 1,300 jobs per year over the primary construction period 2013 to 2015, with peak employment impacts estimated at 1,370 – 1,670 jobs in 2013. Economic output (sales) in New Hampshire is estimated to increase by $259 million to $316 million over the whole planning and construction period of 2010 to 2015, with an average annual increase of $74 million to $91 million during the primary construction period. Household earnings for New Hampshire residents are estimated to increase by a total of $204 million to $249 million during 2010 through 2015, averaging an annual increase of approximately $56 million to $69 million between 2013 and 2015, the primary construction period.

Proposed Northern Pass Transmission Project
Preliminary Select Annual Economic Impacts on New Hampshire
Primary Construction Phase, 2013-2015
(2010 Dollars)

Economic Indicator	Average Per Year
New Hampshire Employment	1,100 – 1,300 Jobs
New Hampshire Economic Output / Sales	$74 Million - $91 Million
New Hampshire Household Earnings	$56 Million - $69 Million

[2] Additional information about the US Department of Commerce's Bureau of Economic Analysis' RIMS II multipliers can be found at http://www.bea.gov/regional/rims/index.cfm

The estimated employment impacts reflect direct New Hampshire employment in the in-state professional, technical services, site work, and construction industries associated with the design and construction of the project, and the indirect and induced in-state employment through the multiplier effect. Indirect and induced jobs are associated with the purchases of New Hampshire goods and services stemming from the project's direct in-state expenditures as well as the spending by New Hampshire employees who are directly and indirectly employed due to the project. Economic activity may also result when people from out-of-state who are working on the project come to New Hampshire and spend money (for example, at gas stations, restaurants, hotels and stores), although the economic impacts from these expenditures on specialized materials and labor are not included in the estimates reported here.



* Employment figures reported in this chart reflect the midpoints of the ranges for each year.

Economic output, or sales, captures all of the intermediate goods purchased as well as all of the final goods and services that are captured in Gross State Product. Based on preliminary estimates, New Hampshire's annual sales are estimated to increase by approximately $89 million to $109 million in 2013, with the average increase in annual sales estimated at $74 million to $91 million during the period 2013

through 2015. Based on the estimated increases in sales each year during the period 2010-2015, the state's output could be an estimated $259 million to $316 million higher, on a cumulative basis, than it would be in the absence of the proposed Northern Pass transmission project.

Proposed Northern Pass Transmission Project
Development and Construction Phase
Impacts on New Hampshire Economic Output
(Millions of 2010 Dollars)

2010	2011	2012	2013	2014	2015	Total
$7 - $8	$6 - $8	$22 - $27	$89 - $109	$80 - $97	$54 - $66	$259 - $316

The employment impacts and economic activity estimated to result from the proposed Northern Pass transmission project will in turn lead to greater household earnings for New Hampshire households. Based on preliminary estimates, New Hampshire household earnings are estimated to increase by a total of $204 million to $249 million during the period 2010 through 2015, averaging an annual increase of approximately $56 million to $69 million between 2013 and 2015, the primary construction period. Annual household earnings are likely to peak in 2013, at an estimated $73 million to $89 million due to heightened construction activity.

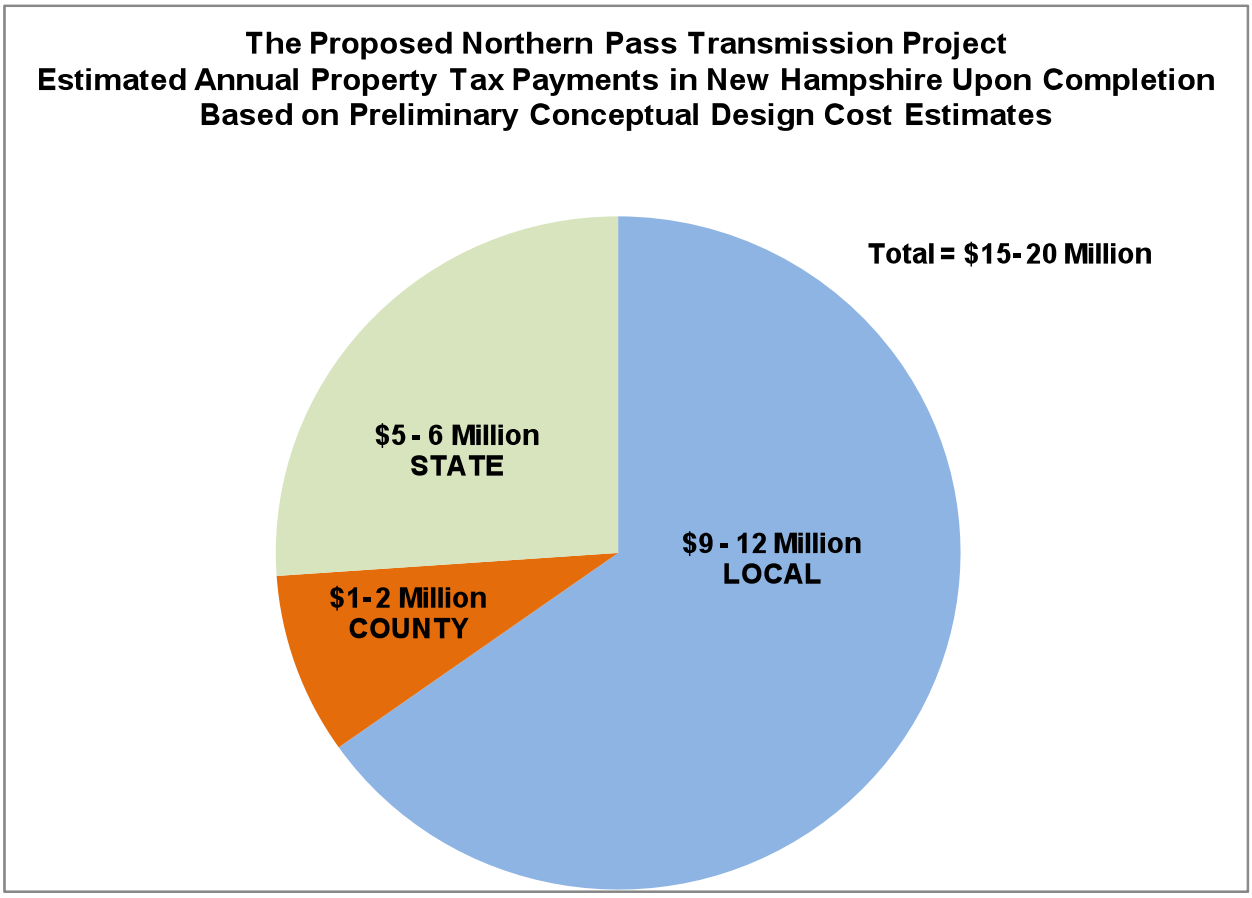
Proposed Northern Pass Transmission Project
Development and Construction Phase
Impacts on New Hampshire Household Earnings
(Millions of 2010 Dollars)

2010	2011	2012	2013	2014	2015	Total
$7 - $8	$6 – $8	$22 - $27	$73 – $89	$57 - $70	$39 - $47	$204 - $249

Estimated Fiscal Impacts (Property Tax Payments) Upon Completion

The Northern Pass transmission project, subject to all regulatory approvals, would add a significant amount of taxable property value in communities in which it would be located, and to multiple counties and the whole state. Rough allocations of costs for the major equipment installations, and per mile cost allocations were provided based on conceptual designs and cost allocations. The 2009 estimated full value tax rates for communities for municipal and local supplemental education expenditures, county expenditures, and the statewide utility property tax were then applied to the allocations. Sensitivities for growth in tax bases and expenditures at the aggregate level were modeled as well.

The resulting estimates are that the Northern Pass transmission project will yield overall property tax payments of $15 million to $20 million a year in local, county, and state property taxes in New Hampshire. The chart below shows the estimated breakouts, based on the preliminary conceptual design cost estimate for the Northern Pass transmission project.



Preliminary Economic and Fiscal Impacts of the Proposed Northern Pass Transmission Project:
Franklin Converter Station and Line Work

October 2010

Prepared for Northern Pass Transmission LLC
By Dr. Lisa K. Shapiro – Chief Economist
And Heidi L. Kroll – Policy Analyst
Gallagher, Callahan & Gartrell PC

Summary

The Northern Pass transmission project is a proposal for a transmission line to bring 1,200 MW of competitively priced, low carbon, renewable energy (predominantly hydropower) from Canada into the Northeast region. HQ Hydro Renewable Energy, Northeast Utilities, and NSTAR are partnering on the proposed Northern Pass transmission project, and have received preliminary approvals from the Federal Energy Regulatory Commission on the proposed funding model. In New Hampshire, the Northern Pass Transmission project is proposed to be located in about 30 communities. The project is still in the design, engineering, and business deal phase. Federal permitting processes are expected to begin this fall, and state permitting in late 2011. The preliminary conceptual cost estimate for the Northern Pass transmission project proposal is $1.1 billion.

Franklin, New Hampshire has been identified as the location for the project's converter terminal. Preliminary conceptual cost estimates for the Franklin part of the total project are about one-quarter of the total project costs, or about $250 million. Subject to all regulatory approvals, the projected construction period in Franklin is approximately a three-year period from 2013 to 2015. Upon completion, this new utility property will add significantly to the taxable property base in Franklin.

The purpose of this report is to provide preliminary estimates of the economic impacts in New Hampshire during the construction phase of the converter terminal and the related facilities in Franklin. A separate report estimates the economic and fiscal impacts of the overall Northern Pass transmission project and on the other communities in New Hampshire which will host the transmission facilities. The economic impacts of the Franklin Converter terminal part of the overall project are summarized below. These results are based on preliminary conceptual cost estimates.

- Summary of Preliminary Estimates -
New Hampshire Economic and Fiscal Impacts of Proposed Northern Pass Transmission Project:
Franklin Converter Terminal and Line Work

Construction Phase (2013-2015)

Annual Average New Hampshire Employment: (Franklin converter terminal only)	300 – 380 Jobs
Annual Average New Hampshire Total Household Earnings:	$12 – $16 Million
Annual Average New Hampshire Total Economic Output:	$18 - $23 Million

Operational Phase

Utility Property Investment in Franklin:	$250 Million

Estimated Economic Impacts in New Hampshire From the Franklin Converter Terminal and Line Work Construction Project

The New Hampshire economic impact estimates for the construction phase of the Franklin converter terminal project are preliminary, relying on a range of conceptual cost estimates, regional and industry average allocations for local versus non-local labor and materials budgets, assumptions about job types and average wages, and simple static multipliers (RIMS II [i])). This report thus provides a first order approximation of the economic impacts of a $250 million converter terminal and line work construction project in Franklin on New Hampshire employment, output, and household earnings.

This model does not distinguish between economic benefits to Franklin, versus the region and the state as a whole; however, it is expected that a significant portion of the statewide benefits from the converter terminal project in Franklin will accrue to Franklin and the surrounding areas as local vendors and workers are likely to participate. Only the direct expenditures for the project expected to be made in New Hampshire (about one-third) are analyzed to estimate the total economic impact on New Hampshire. The remaining direct expenditures on specialized material and labor from out-of-state are not included in the model for estimating the economic impacts on New Hampshire during the construction phase of the Franklin converter terminal project.

Economic impacts derive first from an estimate of the direct jobs in New Hampshire generated by the Franklin part of the project. Direct jobs in professional and technical services, site work, and construction industries are expected. The RIMS II model then considers these direct expenditures and jobs, and estimates the indirect and induced additional jobs, wages and salary, and overall economic activity supported by these direct expenditures through a multiplier effect. Economic output, or sales, captures all of the intermediate goods purchased as well as all of the final goods and services that are captured in Gross State Product. Total output can be thought of as the total sales or economic activity generated by the project. The employment impacts and economic activity estimated to result from the proposed construction of the converter terminal in Franklin will in turn lead to greater household earnings. Economic activity may also result when people from out-of-state who are working on the project come to Franklin and spend money (for example, at gas stations, restaurants, hotels and stores), although the economic impacts from these expenditures are not included in the estimates reported here. An estimated 340 jobs per year, on average, are expected to be supported by the converter terminal construction project. While this estimate is for total New Hampshire jobs, it is expected that a significant number will be in Franklin and the surrounding areas as local contractors and workers are on-site. The total economic impacts are outlined in the chart below.

[i] US Department of Commerce's Bureau of Economic Analysis' RIMS II multipliers, http://www.bea.gov/regional/rims/index.cfm.

Proposed Northern Pass Transmission Project Franklin Converter Terminal and Line Work Construction Phase, 2013-2015 Preliminary Select Economic Impacts in New Hampshire (Millions of 2010 Dollars)					
Economic Indicator	**2013**	**2014**	**2015**	**Total***	**Average Per Year**
Employment	100 – 125 Jobs	430 – 540 Jobs	375 – 470 Jobs		300 – 380 Jobs
Economic Output/ Sales	$6 - $8	$26 - $33	$23 - $29	$55 - $69	$18 - $23
Household Earnings	$4 - $5	$18 - $22	$16 - $19	$37 - $47	$12 - $16

** Ranges reported for each year may not sum to the Total due to rounding.*

Fiscal Impacts from Franklin Converter Terminal and Line Work

The $250 million energy infrastructure investment, subject to all regulatory approvals, would add a significant amount of taxable property value in Franklin. The $250 million investment would also add to the county tax base as well as the state utility property tax base.

Exhibit No. NPT-206

Excerpts from 2010 ISO-NE RSP

ISO new england

REGIONAL SYSTEM PLAN

2010

10TH ANNIVERSARY ISSUE

2010 Regional System Plan

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October 28, 2010

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Section 1
Executive Summary

The ISO New England (ISO) *2010 Regional System Plan* (RSP10) presents the results of load, resource, and transmission analyses of New England's electric power system for the 10-year planning period through 2019. The report describes the major factors influencing the development of the electric power system for these future years and how the region can provide a reliable and economic system in compliance with federal and state regulations and guidelines. In addition to complying with the ISO's *Transmission, Markets, and Services Tariff*, approved by the Federal Energy Regulatory Commission (FERC), RSP10 meets the criteria and requirements established by the North American Electric Reliability Corporation (NERC), the Northeast Power Coordinating Council (NPCC), and the region.[8] The ISO conducts the planning process in full compliance with Attachment K of its *Open Access Transmission Tariff,* which is part of the ISO tariff.[9]

1.1 Major Findings and Observations

This section presents an overview of the major findings of RSP10 load forecasts; supply and demand resource and transmission planning; market outcomes; economic studies; and other programs, projects, and initiatives that are part of the system planning process.[10] The sections of the report that contain more details of these findings and observations are indicated.

For all RSP10 analyses, the ISO applied a number of assumptions, which are subject to uncertainty over the course of the planning period. Some factors subject to change, which may vary RSP10 results and conclusions, are as follows:

- Demand forecasts
- Resource availability
- Timing of planned system improvements
- Fuel price forecasts
- Market rules and governmental policies
- Technology development

The ISO conducts sensitivity analyses to account for these factors, which could influence the development of needed transmission. While each RSP is a snapshot in time, the planning process is continuous, and the results are revisited as needed, accounting for appropriately updated information, such as load forecasts.

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[8] *ISO New England Inc. Transmission, Markets, and Services Tariff*, Part II, Section 48 (ISO tariff) (2010); http://www.iso-ne.com/regulatory/tariff/index.html. Information on NERC requirements is available at http://www.nerc.com. Information on NPCC is available at http://www.npcc.org/.

[9] *ISO New England Open Access Transmission Tariff*, Section II, Attachment K, "Regional System Planning Process" (December 7, 2007); http://www.iso-ne.com/regulatory/tariff/sect_2/oatt/2-1-09_sect_ii.pdf.

[10] In general, *supply resources* are generating units that use nuclear energy, fossil fuels (such as natural gas, oil, or coal), or renewable fuels (such as water, wind, or the sun) to produce electricity. *Demand resources* are measures that reduce consumer demand for electricity from the power system, such as using energy-efficient appliances and lighting, advanced cooling and heating technologies, electronic devices to cycle air conditioners on and off, and equipment to shift load to off-peak hours of demand. They also include using *distributed generation* (DG) (i.e., electricity generated on site).

1.1.1 Forecasting the Annual and Peak Use of Electric Energy and Load Growth

The RSP10 forecasts incorporate the expected effects of federal energy-efficiency (EE) standards for appliances and commercial equipment that will go into effect in 2013 and the historical energy-efficiency savings. Increases in state-sponsored EE programs, enrolled with the ISO as "other demand resources" (ODRs), contributed to the declines in electric energy demand in 2008 and 2009.[11] The increased energy savings attributable to ODRs reduced the growth in weather-normalized electric energy consumption by 50% from 2008 to 2009.[12] The peak load forecasts also account for updates in the historical weather data. These forecasts reflect the growth of the summer cooling load and a lower rate of growth of the winter heating load. (Section 3)

The expected summer peak forecast is 27,190 megawatts (MW) for 2010, which grows to 30,730 MW for 2019. The ISO forecasts the 10-year growth rate to be 1.4% per year for the summer peak load, 0.5% per year for the winter peak load, and 0.9% per year for electric energy. The annual *load factor* (i.e., the ratio of the average hourly load during a year to peak hourly load) declines from 55% in 2010 to 53% in 2019. This decrease indicates the less efficient use of electric power system infrastructure. (Section 3)

The forecasts are lower mainly due to the economic recession that began in 2008, reached its low point in 2009, and is expected to begin a weak recovery in late 2010. The lower load forecast affects the need for new resources and may delay the timing of some transmission projects. (Section 3)

1.1.2 Identifying Needs for Capacity and Operating Reserves

The ISO's system planning process identifies the needs for capacity and operating reserves. These needs are met through the Forward Capacity Market (FCM) and the locational Forward Reserve Market (FRM).

1.1.2.1 Capacity

The regional development of generation and demand resources is expected to provide the capacity needed to meet resource adequacy requirements (i.e., the minimum amount of capacity the region will require, called the *Installed Capacity Requirement*; ICR). The net ICR is expected to grow from 31,110 MW in 2011 to a representative value of 34,818 MW by 2019. (Section 4)

Assuming the over 35,000 MW of resources that cleared the third Forward Capacity Auction (FCA #3) for the capacity commitment period for 2012/2013 remain in commercial operation beyond 2012, and no generation or demand resources retire or permanently delist, New England should have adequate resources through 2019.[13] Recent modifications to the FCM require the procurement of resources that

[11] *Other demand resources* consist of three types of demand resources: energy efficiency, load management, and distributed generation. These types of resources typically are nondispatchable and tend to reduce end-use demand on the electricity network across many hours but usually not in direct response to changing hourly wholesale prices. Refer to the ISO's *2009 Regional System Plan* (RSP09), Section 4.2.4.3, (October 15, 2009) for additional information on ODRs; http://www.iso-ne.com/trans/rsp/2009/index.

[12] *Weather-normalized* results are those that would have been observed had the weather been the same as the long-term average weather.

[13] A *capacity commitment period* runs from June 1 through May 31 of the following year. Existing capacity resources are required to participate in the FCA and are automatically entered into the capacity auction. However, these resources may indicate a desire to be removed from the FCA by submitting a delist bid before the existing-capacity qualification deadline.

meet both resource adequacy and transmission security needs, which ensure adequate resources in import-constrained areas.[14] (Section 4)

1.1.2.2 Operating Reserves

Resources participating in the locational Forward Reserve Market are helping to satisfy the operating-reserve requirements of the region overall and of major load pockets in New England to cover *contingencies* (i.e., the sudden loss of a generation or transmission power system element). As a result of transmission upgrades and other resource additions, the Greater Southwest Connecticut area is not expected to need any local operating reserve for 2010 to 2014.[15] Over the same period, the forecasted need for the Greater Connecticut area is 700 to 1,250 MW, and the need for the BOSTON area is in the range of 0 to 150 MW.[16] The addition of in-merit generation within the major import areas, improvements to the transmission system, or some combination of both would decrease the need to locate operating reserves within these areas.[17] A Demand-Response Reserves Pilot Program, completed in June 2010, assessed the ability of demand resources to provide operating reserves; the ISO and regional stakeholders are developing a follow-up program based on the results of the pilot.[18] (Section 5)

1.1.3 Identifying Transmission System Needs and Solutions

Key inputs to the transmission planning process are peak demand and electric energy growth, as well as the development of resources, including renewable and demand resources. Upgrades to the transmission system since 2002 have improved the New England transmission infrastructure; maintained power system reliability in accordance with NERC, NPCC, and ISO criteria and standards; and further reduced congestion costs and other charges.[19] (Section 6)

Transmission planning studies, done collaboratively with transmission owners (TOs) and other stakeholders, have identified future reliability needs of the region and transmission improvements to solve them. Projects currently being identified, planned, and implemented are also laying the foundation for integrating new resources, including renewable energy resources, and are improving the economic performance of the system. The RSP10 identifies the continued need for transmission development across the region and summarizes the status of ongoing transmission studies and the results of projects in various stages of implementation. (Section 6)

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[14] *Order on Forward Capacity Market Revisions and Related Complaints*, FERC Docket Nos. ER10-787-000, EL10-50-000, and EL10-57-000 (April 23, 2010); http://www.iso-ne.com/regulatory/ferc/orders/2010/apr/er10-787-000_el10-50_el10-57_order_fcm_redesign.pdf.

[15] To conduct some RSP studies, the region is divided into various areas related to their electrical system characteristics. *Greater Connecticut* is an area that has boundaries similar to the State of Connecticut but is slightly smaller because of electrical system limitations near Connecticut's borders with western Massachusetts and Rhode Island. *Greater Southwest Connecticut* includes southwestern and western portions of Connecticut. The *BOSTON* area (all capitalized) includes the city of Boston and northeast Massachusetts. (See Figure 2-2.)

[16] The ISO develops the representative operating-reserve requirements of these major import areas as ranges to account for future uncertainties about the availability of resources, load variations due to weather, and other factors.

[17] *In-merit generation* is when the generators with the lowest-price offers are committed and dispatched first, and increasingly higher-priced generators are brought on line as demand increases. *Out-of-merit dispatch* is when higher-priced generators are committed and dispatched before lower-priced resources to respect system reliability requirements, which results in increased costs to load.

[18] *Demand response* in wholesale electricity markets occurs when market participants reduce their consumption of electric energy from the network in exchange for compensation based on market prices.

[19] The ISO is subject to audits, which must prove compliance with all planning requirements. The last NERC/NPCC audit report, *Compliance Audit Report Public Version: ISO New England Inc. April 20 to April 24, 2009* (May 7, 2009; posted January 5, 2010), is available at http://www.npcc.org/compliance2/AuditSpot.aspx.

1.1.3.1 Transmission Projects

The *RSP Project List* is a summary of transmission projects under various stages of development (i.e., concept, planned, proposed, and under construction), as required under Attachment K of the OATT to meet regional system needs.[20] It also includes information on project status and cost estimates. The descriptions of transmission projects in RSP10 are based on the June 2010 update, which includes 189 projects at a total cost of approximately $5 billion.[21] On the basis of these costs, the Regional Network Service (RNS) transmission rate is expected to grow from $64.83/kilowatt-year (kW-year) in 2010 to $110.07/kW-year in 2014, an increase of almost 70%.[22] (Section 6)

The ISO updates the *RSP Project List* at least three times per year, as improvements are identified and projects are completed or eliminated from the list. In addition, the ISO regularly discusses system needs and the justification for transmission improvements with the PAC and the Reliability Committee, which provide guidance and comment on study scopes, assumptions, and results. All transmission projects are coordinated with other regions as well. The ISO will continue to work with regional TOs to improve project management cost estimates, cost transparency, and cost controls and provide timely and accurate transmission project cost estimates throughout the development of transmission projects. (Section 6)

The status of several major projects under development is as follows:

- The Maine Power Reliability Program (MPRP), for which the Maine Public Utilities Commission (MPUC) has approved most of the components, establishes a second 345 kilovolt (kV) path in the north from Surowiec to Orrington and adds new 345 kV lines in southern Maine, creating a third parallel path from Surowiec to Three Rivers. These new paths will provide basic infrastructure necessary to increase the ability to move power into Maine from New Hampshire, improve the ability of the transmission system within Maine to move power into the local load pockets as necessary, and increase transfer capability through Maine.[23] (Section 6)

- The New England East–West Solution (NEEWS) series of projects had been identified to improve system reliability: (Section 6)

    - As a result of the Needs Assessments and Solutions Studies conducted by the ISO and the completion of the siting proceedings completed by the affected states (Massachusetts,

[20] The current update of the *RSP Project List* is available at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/index.html.

[21] Cost estimates without transmission cost allocation approval are subject to wide ranges of accuracy and change as projects progress through various stages of implementation. The $5 billion cost estimate has a range $3.8 to $6.2 billion based on projects that are proposed, planned, and under construction. See the June 2010 *RSP Project List* presentation, slide 9, at http://www.iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/projects/2010/june_proj_list_slides.pdf.

[22] Participating transmission owners' (PTOs') annual informational filing regarding ISO tariff charges in effect as of June 1, 2010, pursuant to FERC Docket Nos. RT04-2-000, et al.(July 30, 2010); http://iso-ne.com/regulatory/ferc/ptoac/2010/jun10_sch_9_1_info_filing.pdf.
PTO presentation to the RC and TC (August 16–17, 2010) explaining the basis of the RNS rate; http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2010/aug16172010/a11_2010_rns_rates_presentation.pdf.
Second presentation projecting the RNS rate for five years using a number of assumptions; http://www.iso-ne.com/committees/comm_wkgrps/trans_comm/tariff_comm/mtrls/2010/aug16172010/a11_rns_rate_forecast_%202010_2014.pdf.

[23] *Load pockets* are areas of the system where the transmission capability is insufficient to import power from other parts of the system and load must rely on local generation. The ISO is studying changes in the export-transfer capability from Maine to New Hampshire.

Connecticut, and Rhode Island), the Springfield and Rhode Island components of NEEWS should be placed in service as soon as possible.

- The Interstate Reliability Project and the Central Connecticut Reliability Project were reevaluated to account for the RSP10 load forecast, system operating constraints, resources acquired and delisted through the Forward Capacity Auctions, the impact of the unavailability of the Kleen Energy facility in Connecticut, and the possibility that the Vermont Yankee plant will not remain operational.
  - On the basis of studies that considered these and other factors, the Interstate Reliability Project is needed to meet national and regional reliably criteria and serve load throughout southern and eastern New England. One need is to ensure deliverability of FCA-cleared resources from western New England to eastern New England and vice versa. The system Needs Assessment also identified the need for relieving generator mechanical stress issues, reducing high short-circuit availability at key substations, and improving system resiliency to withstand extreme contingencies and the retirement of generating units. The final alternatives for the Interstate Reliability Project remain under study. (Section 6)
  - The need for the Central Connecticut Reliability Project is also under study.

Plans call for discussing these remaining studies with the PAC by the first quarter of 2011.

At various times, generating units in New England load pockets have been in "must-run" situations to serve area load reliably. These load pockets include portions of Maine, the Boston area, southeastern Massachusetts (SEMA), western Massachusetts, the Springfield area, and Connecticut. In addition to improving reliability, transmission improvements placed in service have reduced load costs associated with second-contingency and voltage-control payments to generators.[24] The Lower Southeastern Massachusetts (Lower SEMA) short-term upgrades are one example of transmission improvements that have improved reliability, reduced dependencies on generating units, and reduced "make-whole" payments to market participants with resources whose operating costs were higher than their energy market revenues over a 24-hour dispatch day. (Section 6)

Several developers have proposed elective and merchant transmission upgrades, which are in various stages of study and development. These projects could increase New England's tie capability with its neighbors and improve access to renewable sources of energy. The ISO will continue to monitor projected system conditions and needs based on the outcomes of these upgrades. (Section 6)

1.1.3.2 Interregional Planning

ISO New England's planning activities are closely coordinated among the six New England states and other New England stakeholders, as well as with neighboring systems and nationally with the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission, and NERC. The ISO has coordinated system plans and has proactively initiated planning studies with other regions.[25] The Northeastern ISO/RTO (Independent System Operator/Regional Transmission Organization) Planning

[24] A *second contingency* is when a power system element is unavailable and another contingency occurs.

[25] The *2009 Northeast Coordinated System Plan* (ISO New England, New York ISO [NYISO], and PJM Interconnection [PJM], May 24, 2010) summarizes several interregional planning activities. The report is available at http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/ncsp/index.html. PJM is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.

Protocol has further improved interregional planning among neighboring areas. Sharing more supply and demand resources with other systems will likely become necessary, particularly, to meet environmental emission initiatives (see below). Identifying the potential impacts that proposed generating units and transmission projects could have on neighboring systems is beneficial to support interregional reliability and economic performance. (Section 11)

In August 2009, a coalition of the regional planning authorities within the Eastern Interconnection formed the Eastern Interconnection Planning Collaborative (EIPC).[26] The EIPC is a first-of-its-kind effort to address North American planning issues, coordinate plans, and conduct studies for the entire Eastern Interconnection through a transparent and collaborative process with input from a broad base of interested stakeholders. Participants include federal and state policymakers; Canadian provincial officials; consumer and environmental advocates; transmission owners and developers; generation owners; other suppliers; and representatives from transmission-dependent utilities, public power companies, and electric cooperatives within the Eastern Interconnection. ISO New England and other planning authorities throughout the Eastern Interconnection are principal investigators in the EIPC process. The EIPC proposes to use local and regional planning processes and studies as the basis for performing new interconnection-wide analyses of various transmission alternatives. (Section 11)

The ISO participates in several other national and regional system planning forums, such as the Electric Reliability Organization, the ISO/RTO Council, and the Northeast Power Coordinating Council. The ISO is conducting a joint production-cost study with the New York ISO (NYISO) and PJM Interconnection (PJM) based on stakeholder requests received in 2009. This study is identifying transmission constraints limiting interregional power transfers and showing the effects of relaxing these constraints throughout the ISO/RTO regions. ISO New England will continue to coordinate efforts with neighboring systems to plan projects jointly, explore the ability to import power from and export power to the eastern Canadian provinces and New York, and participate in national and regional planning activities. (Sections 10 and 11)

1.1.4 Developing and Integrating Resources

In addition to identifying the need for capacity and operating reserves, the ISO's system planning process assesses the impacts of fuel diversity and environmental initiatives. It also identifies and resolves issues related to developing and integrating renewable resources, demand-resource applications, and smart grid technologies.

1.1.4.1 Fuel Diversity

New England will remain heavily dependent on natural gas as a primary fuel for generating electric energy for the foreseeable future; natural gas plants currently represent 41% of the region's capacity and provided about 42% of the system's electrical energy in 2009. Recent improvements to the regional and interregional natural gas infrastructure have helped expand and diversify natural gas sources to meet New England's increasing demand for natural gas to produce electric power.[27] Also, the implementation of operating procedures and improved communications between electric power and natural gas system

[26] The *Eastern Interconnection* consists of the interconnected transmission and distribution infrastructure that synchronously operates east of the Rocky Mountains, excluding the portion of the system located in the Electric Reliability Council of Texas (ERCOT) and Québec. Additional information on the EIPC is available at http://www.eipconline.com/.

[27] Improvements include a new liquefied natural gas (LNG) terminal in St. John, New Brunswick; the Northeast Gateway Project and Neptune LNG terminals, both offshore of Gloucester, MA; increased sources of natural gas from shale, such as the Marcellus Shale discoveries, and developments in Atlantic Canada (Deep Panuke); and several improvements to natural gas pipelines and storage facilities.

operators have decreased operational risks and improved the reliability and diversity of natural gas supply and transportation. These steps have mitigated electric power system reliability concerns.[28] (Section 7)

1.1.4.2 Environmental Emissions Requirements

The region and neighboring areas face extensive state and federal environmental initiatives that cover air emissions, water intake requirements, and the handling of coal combustion products.[29] These regulations will continue to increase fossil fuel plant operating costs for emission allowances, add capital costs for environmental controls, and require the use of low-emitting fuels, which may limit generation capacity or energy production. The limited availability of emission allowances also could constrain generation capacity and fossil-fueled energy production, which could lead to new generation dispatch and commitment patterns and shifting costs. The ISO will monitor and evaluate environmental initiatives as they occur or are proposed and provide feedback and input to environmental regulators on the impacts the initiatives could have on power system operations and reliability. (Section 8)

Over the past 10 years, generating units in the region have been using cleaner fuels, particularly natural gas, and have added emission controls. As a result, the region's average and marginal emission rates for sulfur dioxide, nitrous oxides, and carbon dioxide have continued to decline.[30] Total emissions for SO_2 and NO_X also have continued to decrease with time. (Section 8)

Some aging generation facilities may retire before 2019 (the last year of this 10-year plan) because of the impact of stricter environmental regulations. However, the FCM allows resources with a significant investment in environmental upgrades to qualify as new resources, making them eligible for established FCM revenues for up to five years. Much of the 1,671 MW of new generation resources that cleared FCA #3 are from enhancements to existing facilities retrofitting to meet environmental regulations. (Sections 4 and 8)

1.1.4.3 Renewables, Demand Resources, and the Smart Grid

Environmental regulations and policies, such as the Regional Greenhouse Gas Initiative (RGGI) and Renewable Portfolio Standards (RPSs), are stimulating the need for and development of renewable resources and energy efficiency in the region. Other regional and industry efforts are assisting in the process to integrate renewables, demand resources, and smart grid technologies:[31]

- **Meeting State Targets for Renewables and Energy Efficiency—**The New England states have targets for the proportion of electric energy to be met by renewable resources, such as wind and solar, and energy efficiency. These state targets will increase to approximately 30% of New England's total projected electric energy use by 2020. This goal of 30.4% consists of 11% energy-efficiency programs and 19.4% Renewable Portfolio Standards and policies addressing renewable supply and EE goals. Possible solutions for meeting or exceeding the region's RPSs

[28] System operating concerns experienced in the cold snap of 2004 have largely been addressed. *Final Report on Electricity Supply Conditions in New England during the January 14–16, 2004 "Cold Snap"* (October 12, 2004); http://www.iso-ne.com/pubs/spcl_rpts/2004/final_report_jan2004_cold_snap.pdf.

[29] Air emission regulations cover nitrous oxides (NO_X), particulates, sulfur dioxide (SO_2), mercury, and greenhouse gases, such as carbon dioxide (CO_2).

[30] *2008 New England Electric Generator Air Emissions Report* (August 18, 2010); http://www.iso-ne.com/genrtion_resrcs/reports/emission/index.html.

[31] According to the National Electrical Manufacturers Association and the Congressional Research Service, the goal of the smart grid is to use advanced, information-based technologies to increase power grid efficiency, reliability, and flexibility, and reduce the rate at which additional electric utility infrastructure needs to be built. For additional information, see the ISO's *Overview of the Smart Grid—Policies, Initiatives, and Needs* (February 17, 2009); http://www.iso-ne.com/pubs/whtpprs/smart_grid_report_021709_final.pdf.

include developing the renewable resources in the ISO Generator Interconnection Queue, importing renewable resources from adjacent balancing authority areas, building new renewable resources in New England not yet in the queue and small "behind-the-meter" projects, and using eligible renewable fuels in existing generators.[32] If renewable resource development is not meeting the RPSs, the use of state-established Alternative Compliance Payments (ACPs) can serve as a means of addressing the shortfall. (Section 8)

- **Integrating Renewable Resources—**The ISO is conducting a major study of integrating wind resources into the New England system. This study is analyzing various planning, operating, and market aspects of wind integration; simulations that add wind resources up to 12,000 MW; and the conceptual development of a transmission system that can integrate large amounts of wind generation resources. The study, scheduled to be completed in 2010, is developing models of generation output for a hypothesized fleet of wind plants suitable for ISO studies. (Section 9)

- **Integrating Demand Resources—**The operational and market integration of active demand resources, from approximately 1,300 MW in 2010 to over 1,800 MW by 2012, requires careful planning and coordination.[33] Accordingly, control room applications and ISO operating procedures have been modified, and a new communications infrastructure has been implemented. (Section 9)

- **Developing New England's Smart Grid—**Smart grid technologies represent the next stage in the evolution of the power system to improve data acquisition, analysis, control, and efficiency of the electric power grid. In 2010, the DOE approved funding for the ISO and the New England transmission owners to add over 30 new phasor measurement units (PMUs), which will be used to improve the monitoring and operation of the system. The ISO and stakeholders also will support research and development efforts and the establishment of industry standards for integrating smart grid technologies. (Section 9)

1.1.4.4 Economic Studies of Resource Integration

One of the major economic studies of the power system the ISO conducted in 2009 analyzed the development and delivery of large amounts of renewable resources within New England.[34] This study was conducted at the request of the New England governors, made through the New England States Committee on Electricity (NESCOE), who used the study to develop a blueprint for integrating large-scale renewable energy resources into the region's electric power grid.[35] The ISO study demonstrated that the region has abundant sites for developing resources well in excess of its renewable targets, but an appropriate transmission infrastructure needs to be built to interconnect such renewables. The study also

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[32] The *ISO Generator Interconnection Queue* (*queue*) includes those generators that have submitted requests to interconnect to the ISO New England electric power system.

[33] *Active* demand resources reduce load in response to a request from the ISO to do so for system reliability reasons or in response to a price signal. *Passive* demand resources are principally designed to save electric energy use and are in place at all times without requiring direction from the ISO.

[34] Another economic study requested in 2009 by ISO New England stakeholders, as well as stakeholders from NYISO and PJM, is analyzing a series of scenarios for 2013 to account for planned load, resource expansions and retirements, and transmission configurations that could affect these regions. The study will focus primarily on the NYISO and ISO New England systems. Refer to April and May 2009 PAC materials at http://iso-ne.com/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2009/index.html, and May 2009 discussions held with the Inter-Area Planning Stakeholder Advisory Committee (IPSAC) at http://iso-ne.com/committees/comm_wkgrps/othr/ipsac/mtrls/2009/may72009/index.html.

[35] NESCOE is the FERC-approved regional-state committee for providing advisory input to the ISO regarding the development of the RSP.

showed that the aggressive pursuit of New England and nearby Canadian resources could make this region a net provider of low- or non-carbon-emitting resources to the Eastern Interconnection. (Section 10)

In 2010, NESCOE requested the ISO to conduct a follow-up study of replacing aging coal- and oil-fired generating units with efficient, low-pollution-emitting, natural gas combined-cycle units; wind resources within New England; and renewable imports from Canada. This study will further inform government officials as they establish policies that affect the future planning and development of the system. (Section 10)

1.1.5 Supporting State, Regional, and Federal Initiatives that Affect System Planning

The ISO continuously works with a wide variety of state policymakers and other regional stakeholders to upgrade its planning process. Regional initiatives have improved the planning process, such as the transparency of transmission cost estimates and the provision of critical load levels in Needs Assessments. The quality and extent of interregional analyses with neighboring areas has also been evident, as shown by the issuance of the Northeast Coordinated System Plan and the recently formed EIPC. One recently begun initiative will assess the impacts of FCM demand resources and state EE programs on the load forecast, the regional planning studies and processes, and market systems. Stakeholders also have requested additional information on the factors affecting the degradation of the systemwide load factor and whether actions should and can be taken to improve it. Another new initiative will provide additional information on the ability of nontransmission alternatives (NTAs) to meet system needs. Stakeholders have also asked the ISO to consider the retirement of aging, environmentally challenged generating units and conduct transmission planning analyses for some of these scenarios. Plans call for discussing these issues with the PAC beginning in the fourth quarter of 2010 and providing an update on their status in RSP11. (Section 12)

Active involvement and participation by all stakeholders, including public officials, state agencies, NESCOE, market participants, and other PAC members, are key elements of an open, transparent, and successful planning process. The ISO has continued to work with other representatives of the New England states, primarily through the PAC but also through designated representative organizations, such as the New England Conference of Public Utilities Commissioners (NECPUC), the New England Governors' Conference (NEGC), and the Consumer Liaison Group (CLG). As needed, the ISO will work with these groups, as well as NEPOOL members and other interested parties, to support regional and federal policy initiatives. One of these initiatives is compliance with an upcoming FERC ruling, based on a Notice of Proposed Rulemaking on transmission planning and cost allocation.[36] The ISO will continue to provide required technical support to the New England states and the federal government as they formulate policies for the region (Section 12)

1.2 Conclusions

The ISO's *2010 Regional System Plan* provides information on the timing, location, and type of system resources as well as transmission projects necessary to serve load reliably throughout the region through 2019. The economic recession has slowed the growth in summer peak demand, while wholesale electricity markets and other factors have stimulated the successful development of supply and demand resources to meet the needs of the New England region. Assuming no major resource retirements, the need for new power system infrastructure could be delayed or eliminated over the next 10 years.

[36] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Notice of Proposed Rulemaking, FERC Docket No. RM12-23-000 (June 17, 2010); http://ferc.gov/whats-new/comm-meet/2010/061710/E-9.pdf.

7.5.5 Communication Barriers

The ability to operate the power system reliably depends, in part, on the ISO's ability to recognize possible limitations on fuel deliveries to generating resources, while accounting for other potential contingencies. This risk calls for improved coordination and communication between regional fuel suppliers (oil, coal, and gas) and the electric power industry.

The ISO already has a good working relationship with the regional natural gas industry; however, more training and coordinated interindustry drills would improve existing communication protocols. On September 18, 2009, the ISO hosted a full-day training session at its headquarters for members of the Electric/Gas Operations Committee (EGOC). Before 2009/2010 winter operations, the ISO also met with representatives of both the regional oil and natural gas sectors to assess conditions and confirm communications procedures. Future plans call for further training and the identification of opportunities that would further improve the timely exchange of information between the electricity and natural gas sectors.

7.5.6 Price Exposure

The ISO has developed and implemented remedial measures to successfully manage possible fuel-shortage events.[196] The combined effects of a number of these following measures have diminished the operational risks associated with the high dependence on natural gas by New England's electric generation sector:

- Direct engagement and interaction with regional stakeholders
- Improvements to market rules and procedures
- New interindustry coordination and communications protocols
- Prominent infrastructure additions within both sectors

Although most operational risks have been mitigated, economic risks still remain because, in New England, the wholesale price of natural gas is projected to have a direct impact on the wholesale price of electric power.

7.5.7 Other Fuel-Supply Risks

Several other components of the regional fuel-supply chain, in addition to the natural gas industry, can have an impact on the electric power sector. Problems within regional oil markets, for both heavy and light oil; constraints on transporting and importing coal; problems within the nuclear fuel cycle; regional drought; or a combination of several of these problems can have an impact on New England's electric power system operations and wholesale markets.

Table 7-2 shows New England's 2010 summer generation capacity mix categorized by fuel type and in-service dates. As seen in the table, the majority of the oldest units on the system are hydroelectric units. Most of the 40- to 60-year old stations are either coal- or oil-fired, steam-based units. The majority of the 20- to 40-year old units are nuclear and pumped-storage stations. Natural-gas-fired generation is predominantly new (within the last 20 years), with the majority of those stations being constructed after

[196] In response to the cold snap of January 2004, *Market Rule 1*, Appendix H: Operations during Cold Weather Conditions, was developed. In response to the oil and gas infrastructure damage in the Gulf of Mexico from hurricanes Katrina and Rita in fall 2005, ISO Operating Procedure No. 21 (OP 21), *Actions during an Energy Emergency*, was developed; http://www.iso-ne.com/rules_proceds/operating/isone/op21/index.html.

electric utility deregulation in the late 1990s or early 2000s. This is illustrated in Figure 7-4, which compares the capacity and electric energy production for 2000 and 2009. While the capacity of oil units has been reduced from 34% in 2000 to 25% in 2009, their energy production decreased even further from 14.8% to 0.7%.

Table 7-2
New England's 2010 Summer Generation Capacity Mix by Fuel Type and In-Service Dates[a, b, c]

Fuel Type	In-Service Date Before 1950		In-Service Date 1951–1970		In-Service Date 1971–1990		In-Service Date 1991–2000		In-Service Date 2001 and after		Total	
	# of Assets	MW	# of Assets	MW	# of Assets	MW	# of Assets	MW	# of Assets	MW	MW	%
Gas	5	73	0	0	12	1,617	20	3,564	38	7,928	13,181	41.2
Oil	3	10	61	2,485	25	4,014	11	146	21	212	6,866	21.5
Nuclear	0	0	0	0	5	4,629	0	0	0	0	4,629	14.5
Coal	0	0	13	2,570	2	186	0	0	0	0	2,756	8.6
Pumped storage	1	29	0	0	6	1,649	0	0	0	0	1,679	5.2
Hydro	68	774	8	328	160	434	32	23	31	153	1,712	5.4
Other renewables	0	0	1	43	33	633	28	215	58	251	1,142	3.6
Totals	77	887	83	5,426	243	13,162	91	3,948	148	8,543	31,965	100.0
Percentage of total MW		2.8%		17.0%		41.2%		12.3%		26.7%		

(a) Generator assets in this table may be power plants or individual units that make up power plants. Values do not include HQICC, demand resources, or external purchases and sales.

(b) A total of 10,011 MW of new generation has been installed since the start of the markets in May 1999. This total is based on the claimed capability of these assets as of March 2, 2010, and projected capabilities of assets expected to be in service by summer 2010.

(c) Totals may not equal sum because of rounding.

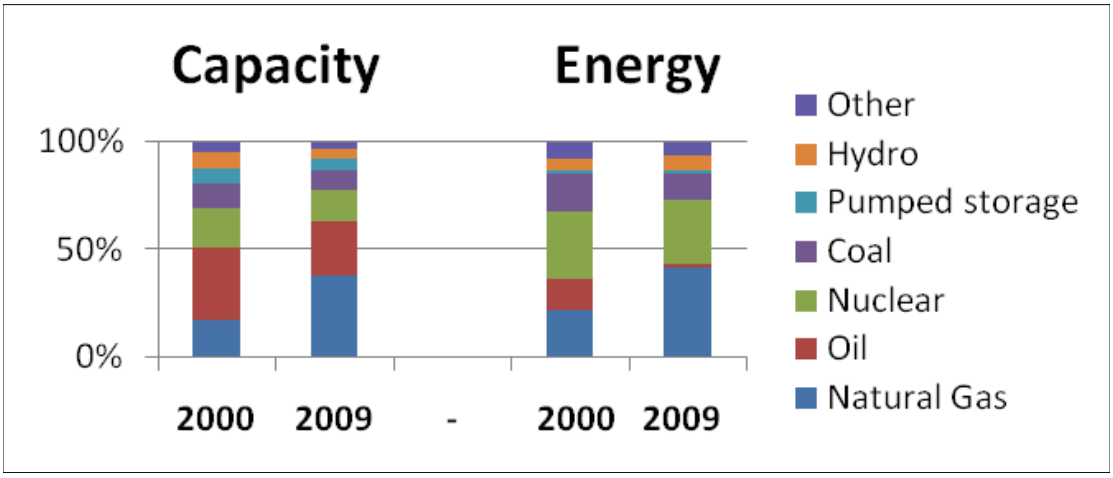

Figure 7-4: Shift in New England's fuel mix, from 2000 to 2009.

Note: The "other" category primarily contains renewable resources.

Environmental initiatives that require reduced air and water emissions are placing increased economic pressure on aging coal- and oil-fired units to add environmental controls or to reduce run times (see Section 8). Given the age of these coal and oil units, these stations may likely retire and be replaced with efficient and relatively clean-burning natural-gas-fired units.

7.6 Summary

While natural gas remains the dominant fuel within New England's electric power generation sector, the region's diversity and expected reliability of natural gas supply has improved. This is the result of the new Canaport LNG terminal that went into commercial operation in 2009 and the Neptune LNG facility that went operational in 2010. In addition, new pipeline expansion projects have been designed to improve the ability to deliver LNG and other sources of natural gas to the region.

Regional gas prices on the spot market, which reached about $15.00/million Btu (MMBtu) in mid-2008, have dropped by about 66% to approximately $5.00/MMBtu in summer 2010.[197] Oil has shown a similar pattern but typically remains more costly than gas on the basis of thermal equivalency. To help mitigate the dependency on natural gas as a single fuel when gas prices are high or supplies are scarce, about 25% of the region's generating plants have dual-fuel capability, the ability to switch between oil and gas as required.

Contingencies on the regional gas supply and transmission system could temporarily limit gas deliveries to generators anytime of the year. Effective communication between gas and electric industry operations helps mitigate these and other reliability concerns. Further flexibility of operation of gas-fired generating units would assist with the reliable integration of variable-output generation resources, such as wind- and solar-powered facilities.

Gas quality and interchangeability will remain a concern, yet minor to date, as more LNG is imported, which can result in different gas compositions that can affect the operation of some types of gas turbines. The natural gas and electric power industries are exploring options to minimize potential problems due to variations in gas quality.

Aging coal- and oil-fired generators are facing additional economic pressures from environmental initiatives. The possibility of these units being replaced or repowered with natural gas could increase the region's dependency on natural-gas-fired generation. Other environmental initiatives are promoting the development of renewable resources and energy efficiency. The addition of these supply- and demand-side resources would reduce the region's dependency on natural-gas-fired generation.

[197] Regional natural gas prices are from the Intercontinental Exchange (ICE) (June 24, 2010); https://www.theice.com/homepage.jhtml.

Section 8
Environmental Regulatory Update

This section provides an update of environmental regulations and initiatives potentially affecting New England generators and the outlook for renewable resource development in the region. It builds on the information presented in RSP09, Section 7. Two new topics are included in this section: historical emissions of New England generation and an overview of the New England states' energy-efficiency (EE) programs. Attachment K of the OATT requires the RSP process to account for, among other things, environmental considerations, which are discussed in this section.

> "The RSP shall address needs of the PTF system determined by the ISO through Needs Assessments initiated and updated on an ongoing basis by the ISO to account for market performance and economic, environmental and other considerations as may be agreed upon from time to time." (Attachment K, Overview)
>
> "The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental and other considerations, as agreed upon from time to time." (Attachment K, § 3.1)

8.1 Update of Environmental Regulations

This section summarizes major environmental activities at the federal and regional levels over the last 12 months that may affect New England generators. The U.S. Environmental Protection Agency (EPA) has been very active during this period in reviewing and proposing new air quality standards and regulations. EPA's actions, along with regional activities, cover the following topics:

- Ozone attainment measures
  - Tighter National Ambient Air Quality Standards (NAAQS) for criteria pollutants that power plants emit or that are created as a byproduct of these emissions: sulfur dioxide (SO_2), nitrogen dioxide (NO_2), fine particulates ($PM_{2.5}$), and ozone (O_3)[198]
  - Clean Air Interstate Rule (CAIR)
  - High Electric Demand Day (HEDD) voluntary measures to reduce ozone[199]
- Carbon dioxide (CO_2) regulation
  - Regional Greenhouse Gas Initiative (RGGI)
  - Other regional and federal cap-and-trade programs
  - EPA's CO_2 regulation and future air regulation strategy
- Power plant cooling water issues addressed by the *Clean Water Act,* Section 316b[200]

[198] Other oxides of nitrogen (NO_X) also contribute to the formation of ozone. The status of these environmental regulatory activities and coverage of proposed changes to EPA's NAAQS, mercury, and coal combustion products is discussed in more detail in the *2009 Northeast Coordinated System Plan*, developed by ISO New England, NYISO, and PJM Interconnection LLC (PJM) (May 24, 2010), 47–61; http://www.iso-ne.com/committees/comm_wkgrps/othr/ipsac/reports/index.html. (PJM is the RTO for all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and the District of Columbia.)

[199] Refer to the Ozone Transport Commission's *Memorandum of Understanding Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electric Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning*, MOU-07-01 (March 2, 2007); http://www.otcair.org/document.asp?Fview=Formal%20Actions#.

- Regional haze[201]
- National Emission Standards for Hazardous Air Pollutants (NESHAPs), including mercury[202]
- EPA's proposed rule on coal combustion byproducts[203]

The issues that likely can have the most significant impacts on New England's power plant operations and costs over the next 10 years are discussed in this section. They include proposed ozone attainment measures, the RGGI cap-and-trade program, federal climate legislation and CO_2 regulation, and cooling water issues.

8.1.1 Ozone Attainment Measures

Proposed ozone attainment measures include the revised NAAQS, HEDD, and the CAIR replacement rule.

8.1.1.1 Revised Ozone Standard

The EPA has proposed revising the March 2008 ozone standard of 75 parts per billion (ppb) to a range of 60 to 70 ppb. As shown in Figure 8-1, more New England areas and the Northeast in general would experience greater degrees of nonattainment of the proposed ozone standard. The figure is based on eight-hour ozone concentrations taken at monitoring sites from 2007 to 2009, and most sites have values exceeding the proposed range for the revised standard (as indicated by the different-colored symbols in the figure, which reflect different ppb values at the monitoring sites). The proposed ozone revision could require further reductions in NO_X emissions in the region and affect some of New England's generators.

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[200] EPA, *Cooling Water Intake Structures, CWA Section 316b; Phase I—New Facilities*. Fact Sheet. EPA-821-F-01-01 (November 2001); http://www.epa.gov/waterscience/316b/phase1/316bph1fs.html.

[201] EPA's regulatory actions related to visibility are summarized at http://www.epa.gov/air/visibility/actions.html. Additional information is available at "EPA's Regional Haze Program" Web page (2009); http://www.epa.gov/air/visibility/program.html.

[202] NESHAPs are emission standards set in EPA's *Clean Air Act,* § 112, for air pollutants not covered by NAAQS that may cause an increase in fatalities or a serious illness. The standards require the maximum degree of emission reduction that EPA determines to be achievable (i.e., the maximum achievable control technology; MACT). For additional information, see "National Emission Standard for Hazardous Air Pollutants" Web page (2010); http://www.epa.gov/apti/course422/apc4e.html.

[203] Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals from Electric Utilities, Proposed Rule, EPA-HQ-RCRA-2009-0640; FRL, Federal Register, vol. 75, No. 118 (June 21, 2010); http://www.epa.gov/epawaste/nonhaz/industrial/special/fossil/ccr-rule/ccr-rule-prop.pdf. Also see http://www.epa.gov/waste/nonhaz/industrial/special/fossil/ccr-rule/index.htm.

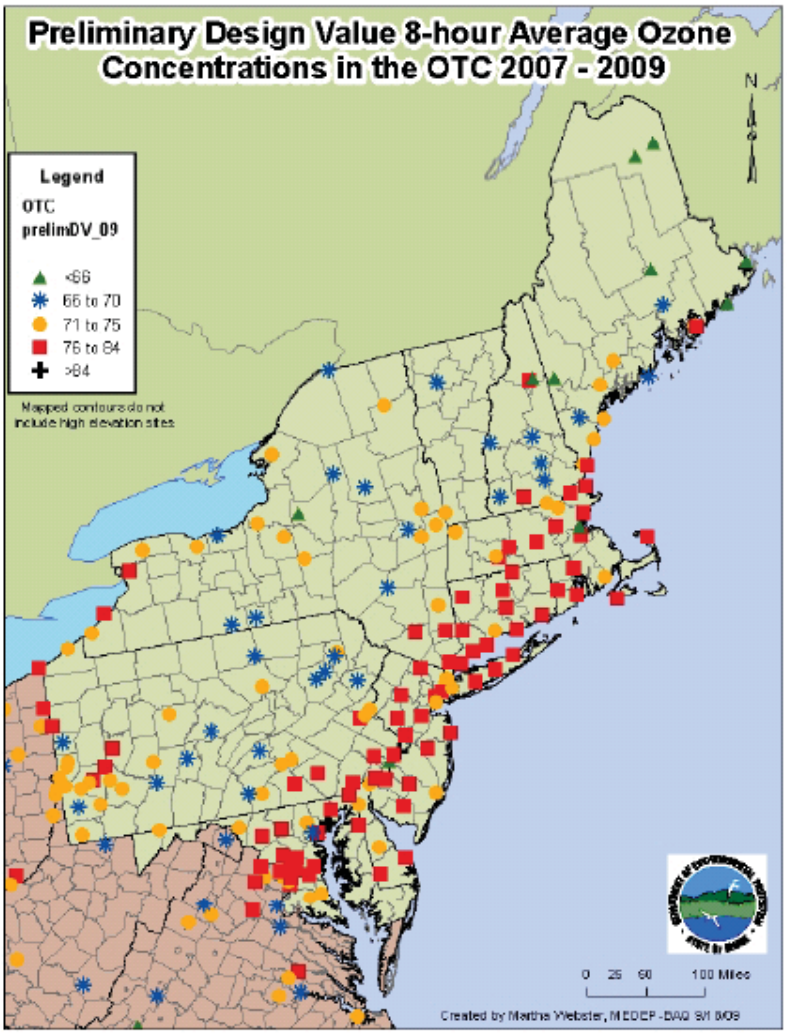

Figure 8-1: Average seasonal concentrations of ozone in the Northeast, 2007 to 2009 (ppb).

Source: Chris Salmi (NJ Department of Environmental Protection [DEP]), "Intro, AQ/Timeline Presentation," Slide 2, Ozone Transport Commission (OTC) Stationary Area and Mobile Sources Meeting, Hartford (March 16, 2010); http://www.otcair.org/document.asp?fview=meeting#). Map created by Martha Webster, Maine DEP.

8.1.1.2 High Electric Demand Days

In addition to meeting the ozone standard, Connecticut is one of six states that signed an OTC commitment for NO_X reductions of 11.7 tons during high electric demand days.[204] The total HEDD NO_X reduction commitment by the six states in the program is 135 tons/day. The HEDD Memorandum of Understanding (MOU) lists alternatives such as adding NO_X controls, repowering or retiring units, reducing output, implementing energy-efficiency and demand-response measures, or capping emissions on HEDDs to reduce NO_X and meet the HEDD commitment. Each state is developing its own strategy

[204] Ozone Transport Commission, *MOU Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electric Demand Days Emission Reduction Strategies into Ozone Attainment State Implementation Planning,* MOU 07-01 (March 2, 2007). New York, New Jersey, Pennsylvania, Maryland, and Delaware also have commitments totaling 123.2 tons of NO_X reductions; http://www.otcair.org/document.asp?Fview=Formal%20Actions#.

and regulations to implement its HEDD commitment; rules must be in place no later than 2012 according to the MOU.

8.1.1.3 CAIR Replacement Rule

The EPA established the *Clean Air Interstate Rule* in March 2005 to reduce precursors to ozone and particulates over 28 eastern states (including Connecticut and Massachusetts) and the District of Columbia. CAIR's objective is to reduce sulfur dioxide and nitrogen oxides, both of which contribute to the formation of fine particulates. NO_X emissions also contribute to the formation of ground-level ozone. CAIR was intended to cap NO_X emissions at 1.5 million tons starting in 2009 and at 1.3 million tons in 2015. CAIR also capped SO_2 levels at 2.5 million tons.

Connecticut and Massachusetts were the only two affected states in New England that would be required to reduce emissions in their states under the original CAIR NO_X cap during the ozone season, which is May through September. These states had been relying on the provisions of CAIR to develop their own compliance rules for generators and had been proceeding with CAIR compliance plans. Generators in these states also had been taking steps toward compliance with these CAIR rules. Connecticut and Massachusetts were not subject to the original CAIR's annual SO_2 or annual NO_X caps.

On July 11, 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated the entire *Clean Air Interstate Rule*.[205] However, on December 29, 2008, the court reversed its July decision and reinstated CAIR indefinitely until the EPA amends the rule or parties appeal the court's decision. On July 6, 2010, EPA proposed a CAIR replacement rule, labeled the *Transport Rule*. As proposed, this rule would only affect Connecticut and Massachusetts by requiring annual caps on SO_2 and NO_X emissions for each state and an ozone season cap starting in 2012 for Connecticut for compliance by larger electric generators.

The ISO will continue to monitor and evaluate developments relating to the proposed *Transport Rule* and any impacts this decision and related state rules could have on New England generators throughout the region.

8.1.2 Greenhouse Gases

The Regional Greenhouse Gas Initiative is a 10-state CO_2 cap-and-trade program that began in 2009 and affects electricity generators. In 2008, CO_2 emissions from RGGI units totaled 153.5 million tons, almost 18% below the current RGGI cap (188.1 million short tons of CO_2). Preliminary EPA data show the 2009 emissions from RGGI units to be even lower at 123.7 million tons (a 34% reduction from the RGGI cap).[206] New England's portion of the 2008 RGGI emissions was 44.3 million tons, almost 21% below its six-state cap allocation of 55.8 million tons. New England's 2009 preliminary emissions were 39.3 million tons, almost 30% below the six-state cap allocation. The lower emissions could be the result of the lower energy consumption driven in part by the economic recession, lower natural gas prices, and the increase in energy production by natural gas units from 40.9% in 2008 to 42.4% in 2009. Adding some longer-term perspective, the 2018 RGGI cap of 169 million tons is 10% lower than the current

[205] North Carolina v. EPA, No. 05-1244, Slip Op. (D.C. Cir., July 11, 2008); http://pacer.cadc.uscourts.gov/docs/common/opinions/200807/05-1244-1127017.pdf.

[206] Office of Air and Radiation, EPA, "EPA Clean Air Markets—Data and Maps, Emissions, Preliminary Quick Reports" Web pages; http://camddataandmaps.epa.gov/gdm/index.cfm?fuseaction=emissions.wizard.

RGGI cap and less than what proposed federal cap-and-trade bills in the U.S. Congress would require: a 17% reduction by 2020 from 2005 emissions.[207]

The RGGI auction prices have dropped to about $2/allowance from over $3/allowance in the first auctions.[208] Total revenues for the New England states from seven RGGI auctions were $177.3 million, of which about 93% or $165.2 million was allocated to these states' energy-efficiency programs (see Section 8.4).[209] A reevaluation of the RGGI program is planned for 2012.[210]

Climate legislation is under development in Congress, with the Senate developing an alternate bill to the Waxman-Markey bill that passed in the House in June 2009.[211] The timetable for when either of these bills could emerge as legislation is uncertain. Both bills are targeting a 17% reduction in greenhouse gas (GHG) emissions by 2020.

EPA had also established an annual GHG emissions reporting requirement for electric generating units with GHG emissions greater than 25,000 metric tons.[212] This requirement started January 1 for the year 2010. EPA also has proposed a GHG permitting requirement for the generating units that would be part of the *Clean Air Act Title V* air permit renewal every five years.[213] The permit would require the use of best available control technology (BACT) or energy-efficiency measures to reduce GHG, but EPA has not yet defined what these would be.

8.1.3 Cooling Water

Cooling water intake requirements for power plants under the *Clean Water Act,* Section 316b potentially could require cooling tower retrofits on some power plants in the region. The revised requirements would result in fewer aquatic organisms being entrained or entrapped in the cooling systems. However, EPA must decide how it will apply a benefit/cost analysis in determining the best available technology (BAT) to make these reductions at power plants. Until this is determined, future requirements will be uncertain when water permits are renewed.

8.1.4 Studies of Potential Generator Retirements

A report sponsored by the Clean Air Policy Initiative of the Clean Energy Group, a coalition of private electric generating companies, analyzed the impacts of EPA's proposed air and water regulations on electric system reliability nationwide.[214] The report concluded that, while the initiatives would result in generator retirements, the excess amount of capacity generally is sufficient to maintain system reliability.

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[207] "Uncertainty clouds KGL release," *Carbon Market North America*, Vol. 5, Issue 16 (April 23, 2010); http://www.pointcarbon.com/news/cmna/1.1439092.

[208] Under RGGI, one allowance equals the limited right to emit one ton of CO_2.

[209] Environment Northeast, RGGI Auction Tracker Web site (2010); http://www.env-ne.org/resources/open/p/id/715.

[210] RGGI Memorandum of Understanding, Section 6D (December 20, 2005); http://rggi.org/docs/mou_12_20_05.pdf.

[211] U.S. Congress, *American Clean Energy and Security Act of 2009*, H.R. 2454, 111th Cong., 1st Sess. (2009).

[212] EPA, "Climate Change Regulatory Initiatives" Web page, "Greenhouse Gases Reporting Program" (2010); http://www.epa.gov/climatechange/emissions/ghgrulemaking.html.

[213] Office of Air and Radiation, EPA, "Fact Sheet—Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (2009); http://www.epa.gov/NSR/fs20090930action.html.

[214] Michael J. Bradley, Susan F. Tierney, et al., *Ensuring a Clean, Modern Electric Generating Fleet while Maintaining Electric System Reliability* (M.J. Bradley and Associates and Analysis Group, August 2010); http://www.mjbradley.com/documents/MJBAandAnalysisGroupReliabilityReportAugust2010.pdf.

Section 13
Conclusions and Key Findings

The ISO's *2010 Regional System Plan* discusses several major results of interest to the region's stakeholders. Success of the Forward Capacity Market and the locational Forward Reserve Market and other factors have resulted in the development of generation and demand resources expected to meet the capacity needs of the New England region over the 10-year planning horizon, assuming no major resource retirements. The economic recession has slowed the growth in summer peak load levels, and RSP10 shows an expected delay of the peaks anticipated in RSP09 by one-and-one-half to two years. While the region has been successful in building needed transmission, the lower load levels and the development of resources where and when they are needed may delay the need for selected transmission projects. The region will continue to depend on natural gas for approximately 40% of its electric energy, but the ISO, regional stakeholders, and the natural gas industry have taken measures to improve the reliability of gas plants and the diversity of the gas supply resources.

Environmental initiatives, such as the Regional Greenhouse Gas Initiative and Renewable Portfolio Standards, are encouraging the development of clean, renewable resources in the region. As a result of economic incentives provided by the wholesale power markets and state policies, wind plants in New England are anticipated to see large growth, and demand resources and energy efficiency are expected to increase. New England has a long history of integrating new technologies into the system, and smart grid improvements are being developed to improve the electric power system's performance and operating flexibility. Economic studies have shown the effects of scenarios that increase renewable resources and demand resources in the region and imports from Canada. These studies have helped provide guidance to policymakers and developers of supply and demand resources and merchant transmission.

The transmission system in New England has evolved significantly over the past several years. From 2002 through 2010, over 300 transmission projects will have been placed in service, and a number are under construction or well into the siting process. Along with the reliability improvements they bring to the system, these transmission upgrades support market efficiency, and the region has seen a significant reduction in congestion costs and other out-of-merit charges, such as second-contingency and voltage-control payments. According to DOE, because of the region's successful "multi-faceted approach" that has spurred investment in new supply- and demand-side resources, as well as planning and development of extensive transmission upgrades, the system currently experiences little system congestion, and it has removed New England as "an area of concern" for the identification of National Interest Electric Transmission Corridors. Additionally, merchant transmission facilities are in various stages of development in the region and have the potential to provide access to renewable resources in remote areas of New England and neighboring regions.

13.1 RSP Tariff Requirements

Attachment K of the OATT specifies that the RSP must discuss the assessment of the system needs of the pool transmission facilities, the results of such assessments, and projected transmission system improvements. The RSP also must identify the projected annual and peak demands for electric energy for a five- to 10-year horizon, the needs for resources over this period, and how such resources are expected to be provided. Additionally, the RSP must include sufficient information to allow market participants, including merchant transmission project developers, to assess several factors to assist them in meeting identified system needs or to modify, offset, or defer proposed regulated transmission upgrades. These factors include the quantity, general locations, operating characteristics, and required availability criteria of incremental supply- and demand-side resources.

As required by the tariff, the ISO works closely with the region's stakeholders through an open and transparent process. In particular, members of the PAC advise the ISO on the scope of work, assumptions, and draft results for the RSP and supporting studies. These studies include Needs Assessments and Solution Studies. Stakeholders can use this detailed information and conduct independent studies using databases available from the ISO to better identify specific locations for market resource development and merchant transmission as alternatives to regulated transmission solutions.

As part of the planning process, the ISO approves transmission projects to meet identified system needs, for which resource alternatives and merchant transmission are insufficient. The transmission projects are included in the ISO's *RSP Project List*.

The ISO has continually met all the requirements of Attachment K of the OATT.

13.2 RSP10 Outlook

RS10 draws the following conclusions about the outlook for New England's electric power system over the next 10 years:

- **Forecasts for the Annual and Peak Use of Electric Energy**—The RSP10 10-year forecast for electric energy demand is lower than the RSP09 forecast, indicating a 0.9% average growth rate in the annual use of electric energy and a long-term 1.4% average growth rate in summer peak use. By the end of the 10-year period, the 50/50 summer peak would be about 530 MW lower than the RSP09 50/50 forecast for 2018.
- **Capacity Need and Resource Development—**Resources with capacity supply obligations in the Forward Capacity Market are exceeding the "representative" 34,818 MW value for capacity resources needed by 2019. Assuming that the over 35,000 MW of resources that cleared the third Forward Capacity Auction remain in commercial operation, New England will have adequate resources through 2019.
- **Operating Reserve—**RSP10 anticipates that the infrastructure required to meet the reliability requirements will be developed successfully and will improve the economical performance of the system from 2010 through 2014. The SWCT and BOSTON import areas may not need any representative operating reserves because of transmission improvements to these areas. The Greater Connecticut import area still has the greatest representative operating reserve need of up to 1,250 MW. The addition of the NEEWS Interstate Reliability Project would reduce the need for locational operating reserves in Greater Connecticut by approximately 50%, while also addressing other system needs. The Demand-Response Reserves Pilot program will offer additional information on the performance of demand resources in providing operating reserve.
- **Transmission System—**Transmission studies have been completed and show the system needs and transmission additions required for the ISO's continued compliance with NERC and NPCC reliability standards and criteria. An additional 38 projects were placed in service in 2009, and an additional 34 projects are expected to be placed in service in 2010. The completed transmission projects are required for providing reliable electric service to load throughout the system and for meeting the demand in areas with significant load growth.

  Transmission improvements already have reduced the costs of second-contingency and voltage-control payments to generation that must run for reliability reasons, especially in Lower SEMA. Additional transmission improvements are planned in that area and other load pockets to improve reliability by further reducing the reliance on must-run generation.

The need for the Interstate Reliability Project portion of NEEWS has been determined, and the final alternatives are under development. The need for the 345 kV portions of the Central Connecticut Reliability Project portion of NEEWS is under study. Plans call for discussing both these studies with the PAC by the first quarter of 2011. The other portions of NEEWS in Springfield and Rhode Island should proceed as planned to serve load reliably in those areas. The MPRP, a project adding major 345 kV facilities from the north to southern parts of Maine, has received most of its approvals from the Maine PUC. Other transmission projects are necessary to serve demand reliably in load pockets, reduce dependencies on must-run generation, and meet load growth throughout the system. The ISO will proceed with projects identified as planned in the *RSP Project List*.

- **Fuel Diversity—**New England will continue to remain dependent on natural gas as the dominant fuel for the region, which provides over 40% of the region's electric energy. Continued enhancement of the regional and interregional natural gas infrastructure serving New England and its neighboring systems, including new pipelines, LNG terminals, and new natural gas sources, will help expand and diversify the region's natural gas supply. Converting gas-fired generation to dual-fuel capability improves reliability and reduces exposure to volatile natural gas prices during shortage periods. Other risk factors have been mitigated through modifications to operating procedures. Modifications to market rules are planned to address resource unit commitment uncertainties and to facilitate the commitment of supplemental or replacement reserves during natural gas shortages. Environmental initiatives are promoting the development of renewable resources and energy efficiency, which would help increase system fuel diversity.
- **Environmental Initiatives—**While subject to revisions, the U.S. *Clean Air Interstate Rule,* the *Clean Water Act* Section 316b specifying cooling water intake requirements, and the Regional Greenhouse Gas Initiative are environmental requirements that will affect or are affecting the region's generators. Power plant options for complying with Section 316b could require capital improvements in thermal discharge systems, including the addition of cooling towers. Compliance with air emission initiatives may require several actions by power plant owners. These could include improving emission control systems, which add capital costs; procuring emission allowances and switching to cleaner fuels, which would increase operating costs; and reducing the permissible run times of the plant, which would reduce revenues from the market. The ISO monitors environmental initiatives, their effects on generating plant operations, and their effects on the overall planning and operation of the power system.
- **Environmental Performance—**The 2008 average emissions for New England generators show a continual decline from previous years. The marginal emission rates have declined as natural gas has become the dominant portion of generation. Compared with 1999, the 2008 average emission rate for SO_2 has declined by 67%, the NO_X rate by 62%, and the CO_2 rate by 12%. Further reductions in emissions are supported by state policies and the ISO markets.

  RGGI allowance auctions to date have provided over $177 million to the six New England states, and over 93% of these funds are targeted for the state energy-efficiency programs. New England's preliminary CO_2 emissions for 2009 are approximately 30% below the cap of 55.8 million tons.

- **Renewable Portfolio Standards and Related Policies—**An ISO analysis based on the 2010 energy forecast shows that Renewable Portfolio Standards and other related goals would result in total demand for renewable resources and energy efficiency reaching 25.5% of New England's total projected energy use by 2017 and 30.4% by 2020. If only 40% of the renewable energy projects in the ISO's Generator Interconnection Queue (as of April 1, 2010) were built, the electric energy from these projects would meet the projected demand for renewable energy in

Exhibit No. NPT-207

September 2010 Article:
"Net Greenhouse Gas Emission at Eastmain 1 Reservoir, Québec Canada"

NET GREENHOUSE GAS EMISSIONS AT EASTMAIN 1 RESERVOIR , QUEBEC, CANADA

Alain Tremblay, Julie Bastien, Marie-Claude Bonneville, Paul del Giorgio, Maud Demarty, Michelle Garneau, Jean-Francois Hélie, Luc Pelletier, Yves Prairie, Nigel Roulet, Ian Strachan, Cristian Teodoru.

ABSTRACT

Growing concern over the long-term contribution of freshwater reservoirs to increased atmospheric concentration of greenhouse gases (GHGs) led Hydro-Québec to study net GHG emissions from Eastmain 1 reservoir. These are the emissions resulting from reservoir creation accounting for GHG produced or absorbed by the natural systems over a 100-year period for the watershed as a whole. This large-scale study was carried out in collaboration with the Université du Québec à Montréal, McGill University and Environnement Illimité Inc. Gross GHG fluxes were measured using different techniques (eddy covariance, chambers, gas, partial pressure, etc.) for both aquatic and terrestrial ecosystems. More than 120,000 measurements were done over 7 years. The data clearly showed that, prior to flooding, the natural ecosystems overall were a low net source of CO_2 and CH_4. Net GHG emissions from Eastmain 1 increased following impoundment and quickly decreased, with a first-order exponential decay as net emissions would likely stabilize around 10 years after flooding. Diffusive fluxes dominate, with degassing and bubbling emissions representing less than 1% of total emissions. CH_4 emissions are very small and represent less than 1% of total emissions. Overall net GHG emissions from Eastmain 1 reservoir are low in comparison with those from a thermal power plant of the same capacity (about 16%) and would be lower when extrapolated to the entire watershed.

RÉSUMÉ

L'intérêt croissant en regard de la contribution des réservoirs à l'augmentation de la concentration des gaz à effet de serre (GES) dans l'atmosphère a amené Hydro-Québec à étudier les émissions nettes de GES au réservoir Eastmain 1. Les émissions nettes sont les émissions émises par le réservoir en considérant celles qui auraient été émises ou absorbées par les milieux naturels à l'échelle du bassin versant et sur une période de 100 ans et. Cette étude d'envergure est réalisée en collaboration avec l'Université du Québec à Montréal, McGill University et Environnement Illimité Inc. Les flux bruts furent mesurés avec différentes techniques (eddy covariance, chambres, pression partielle des gaz, etc.) tant dans les milieux aquatiques que terrestres. Plus de 120 000 mesures ont été réalisées sur une période de 7 ans. Les résultats démontrent clairement que les milieux naturels avant l'ennoiement étaient globalement une source faible de CO_2 et de CH_4. Les émissions nettes du réservoir EM-1 ont augmenté suivant la mise en eau et ont diminué rapidement suivant une courbe exponentielle du premier degré et tout semble indiquer que les émissions se stabiliseront après environ 10 ans. Les émissions sont dominées par les flux diffusifs, le dégazage et l'ébullition représentent moins de 1% des émissions. Les émissions de CH_4 sont très faibles et représentent moins de 1% des émissions totales. Globalement, les émissions nettes de GES du réservoir Eastmain 1 sont faibles en comparaison des émissions d'une centrale thermique de capacité équivalente (environ 16%) et seraient plus petites lorsqu'extrapolées à l'échelle du bassin versant.

1. INTRODUCTION

Lakes, rivers and wetlands, as well as reservoirs, are overall sources of greenhouse gases (GHGs) (Tremblay et al. 2005, Cole et al. 2007, Tranvik et al. 2009). The greenhouse effect is crucial for life on Earth, as it contributes to maintaining a mean annual temperature of about 15°C. However, over the last two decades, the rate of increase of anthropogenic GHG emissions to the atmosphere has reached a critical level. In Canada, hydropower plants represent about 60% of electricity generation capacity. It is generally recognized that boreal run-of-river power plants do not emit GHGs and that hydropower plants with reservoirs have low gross GHG emissions, in the order of 40 to 100 times less per terawatt/hour than those from thermal power plants (Tremblay et al. 2005). Nevertheless, the contribution of freshwater reservoirs to the increase in GHGs in the atmosphere is of growing concern (e.g., St. Louis et al. 2000, Tremblay et al. 2005).

The major GHGs related to reservoir creation are carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) (Eggletion et al. 2006). Water residence time, reservoir shape and volume, and amount and type of vegetation flooded are variables that affect the duration and quantity of emissions (Tremblay et al. 2005). N_2O emissions from reservoirs are typically very low, unless there are significant sources of nitrogen from the watershed (e.g., Tremblay et al. 2005, Eggletion et al. 2006).

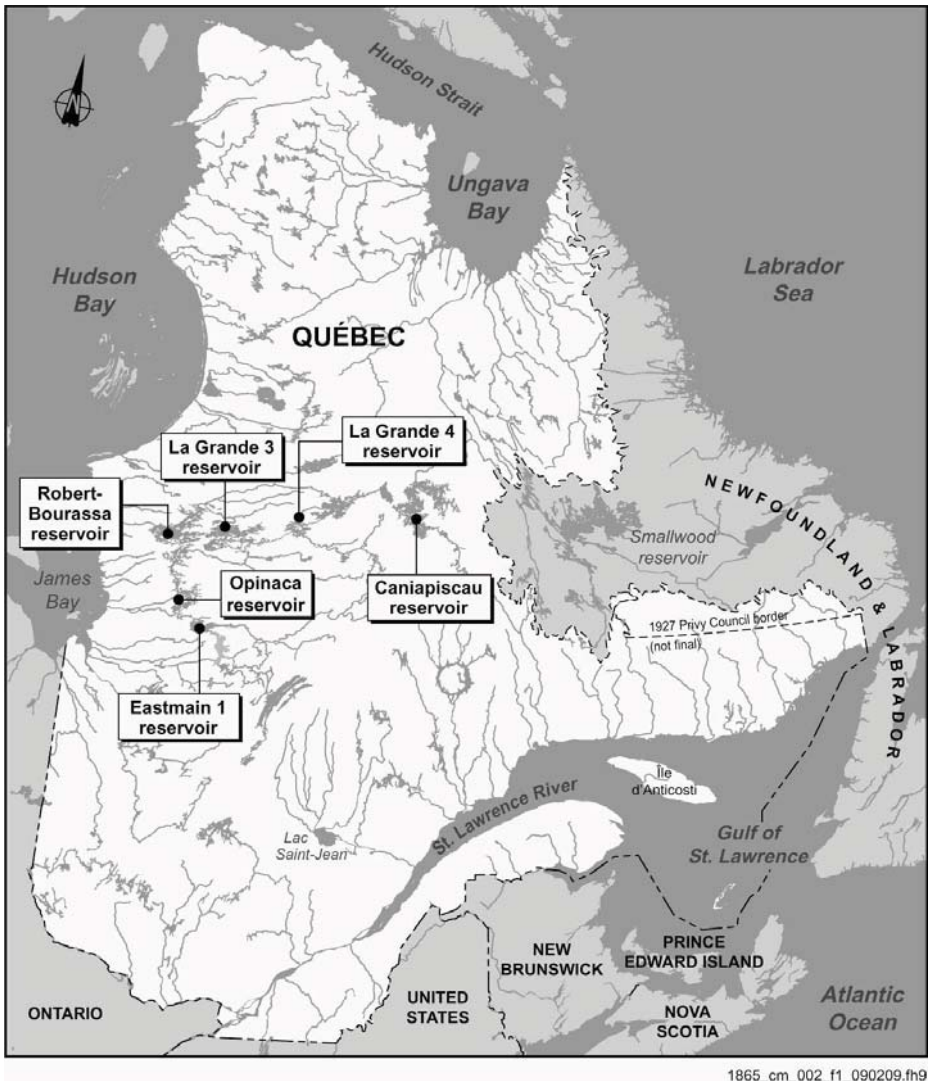
Most of the data available in the literature only account for gross emissions measured at the surface of water bodies and from established reservoirs (>10 years old; e.g., Tremblay et al. 2005, Bastien et al. 2009). Net emissions are emissions resulting from reservoir creation accounting for GHG produced or absorbed by the natural systems over a 100-year period for the watershed as a whole (IPCC, 2006, UNESCO-IHA, 2009). For governments and the energy sector, the evaluation of net GHG emissions from hydroelectric reservoirs is becoming more and more relevant to ensure that methods of energy production are compared adequately and for assessing CO_2 credits. This is the goal of the Eastmain 1 net GHG emissions project (www.eastmain1.org) carried out in collaboration with the Université du Québec à Montréal, McGill University and Environnement Illimité Inc. The objective of this paper is to present net GHG emissions from Eastmain 1 reservoir, a world first.

2. SITE DESCRIPTION AND METHODOLOGY

2.1 Site Description

Eastmain 1 reservoir is located in the boreal ecoregion of Québec, Canada at 52°N, about 1,000 km north of Montréal (Map 1). The watershed of the Eastmain region is dominated by coniferous forest, shallow podzolic and peat soils developed over igneous bedrock and quaternary sediments. Aquatic systems are described as oligotrophic with overall low primary production. The Eastmain-1 powerhouse is equipped with three turbines generating 160 MWh each, for a total of 480 MWh, and was commissioned in 2006. The main dam, along with 33 dikes, form the Eastmain 1

reservoir with a surface area of 603 km^2. An additional 780 MWh will be available by 2012 with the construction of the Eastmain-1A powerhouse, yielding a total energy output from the Eastmain 1 reservoir of about 6.9 TWh per year (from 2012 forward). The hydrology of the Eastmain 1 reservoir basin (35,500 km^2) reflects the regional climate; runoff is strongly seasonal with high flows in the spring (typically peaking in May or June) and low flows in late winter. Eastmain 1 is part of the La Grande hydroelectric complex: the water discharged from Eastmain 1 will ultimately flow into the Opinaca reservoir to be used at the new Sarcelle powerhouse (under construction as part of the Eastmain-1A and Sarcelle powerhouses and Rupert diversion project) and used again at the Robert-Bourassa and La Grande-1 generating stations (Map 1).



Map 1: Northern Québec with the major La Grande complex reservoirs and associated powerhouses, including the new Eastmain 1 reservoir impounded in 2005.

2.2 AQUATIC FLUX MEASUREMENTS AND CALCULATION

The natural aquatic ecosystem is divided into three main categories: river, lakes and streams. Stretching over 138 km within the reservoir area, this section of the Rivière Eastmain covers an area of 82 km^2. Accounting for 55% of the total aquatic surface area, the Rivière Eastmain represents the dominant areal component of the natural aquatic system in the region. Up to 827 lakes contained within the reservoir, with areas between 100 m^2 and 10 km^2, account for 45% of the total aquatic surface. Similarly, 827 streams of various widths and lengths, from only 10 m up to 5.5 km and totaling 1.3 km^2, represent the smallest areal component (less than 1%) of the natural aquatic system.

There are three pathways by which a reservoir may emit GHGs: 1) diffusive emissions, measured at the water-air interface, 2) bubble emissions (mainly CH_4), produced at the sediment-water interface and rising to the water-air interface, and 3) degassing or downstream emissions associated with turbulence at the turbines and spillway outflows (e.g. Tremblay et al. 2005). These three pathways were investigated at Eastmain 1 reservoir.

Diffusive fluxes from the aquatic systems were measured using four different techniques: floating chamber, gas partial pressure, four automated systems and one eddy covariance tower located on Île Marie-Ève (Map 2). More than 150 stations were spread over natural lakes, rivers, the new Eastmain 1 reservoir (one to four years old) and the old Opinaca reservoir (>30 years old) using the floating chamber and gas partial pressure techniques to determine the spatial and temporal variability of GHG emissions (Figure 1). One automated system was installed at Eastmain-1 powerhouse and three were installed on rafts on Eastmain 1 reservoir and on a reference lake. They were visited either by hydroplane or by boat. Sampling was conducted mainly during the ice-free season (May to October) but we also sampled, to a lesser extent, during winter (December to March) to calculate the GHG concentration increase under ice and an annual GHG flux (from ice melting to ice buildup) (Demarty et al. 2009). Diffusive fluxes were measured from 2003 to 2009 both from reference lakes and rivers (outside the present reservoir) and from lakes and rivers that are now part of Eastmain 1 reservoir (three years before flooding). Measurements on Eastmain 1 reservoir were carried out from June 2006 to October 2009 (four years after impoundment).

To calculate fluxes, equations such as gas solubility in water, Henry's law, the Thin Boundary Layer equation, gas transfer coefficient and a series of secondary equations were used, according to the respective technique. Details on the techniques, equations and calculations can be found in Lambert and Fréchette (2005), Demarty et al. (2009), Tremblay et al. (2010) and Teodoru et al. (2009). Annual emissions were estimated from summer fluxes, considering an average ice-free period of 215 days and assuming that the buildup of C pool accumulated under the ice, which quickly decreases within the first month following ice breakup, represents approximately 30% of annual emissions as suggested by CO_2 partial pressure data (Demarty et al. 2009, Ducharme-Riel et al. 2009).

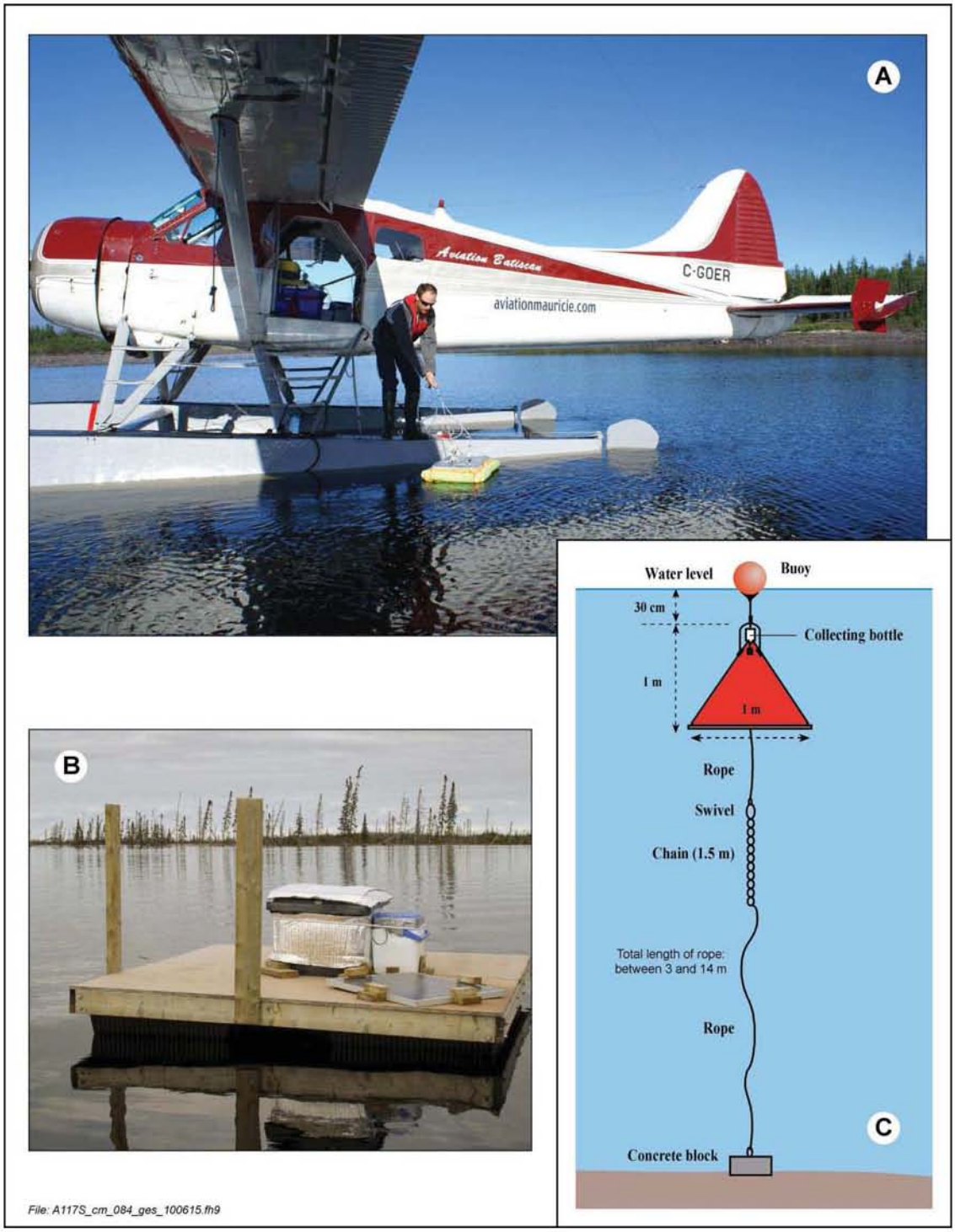
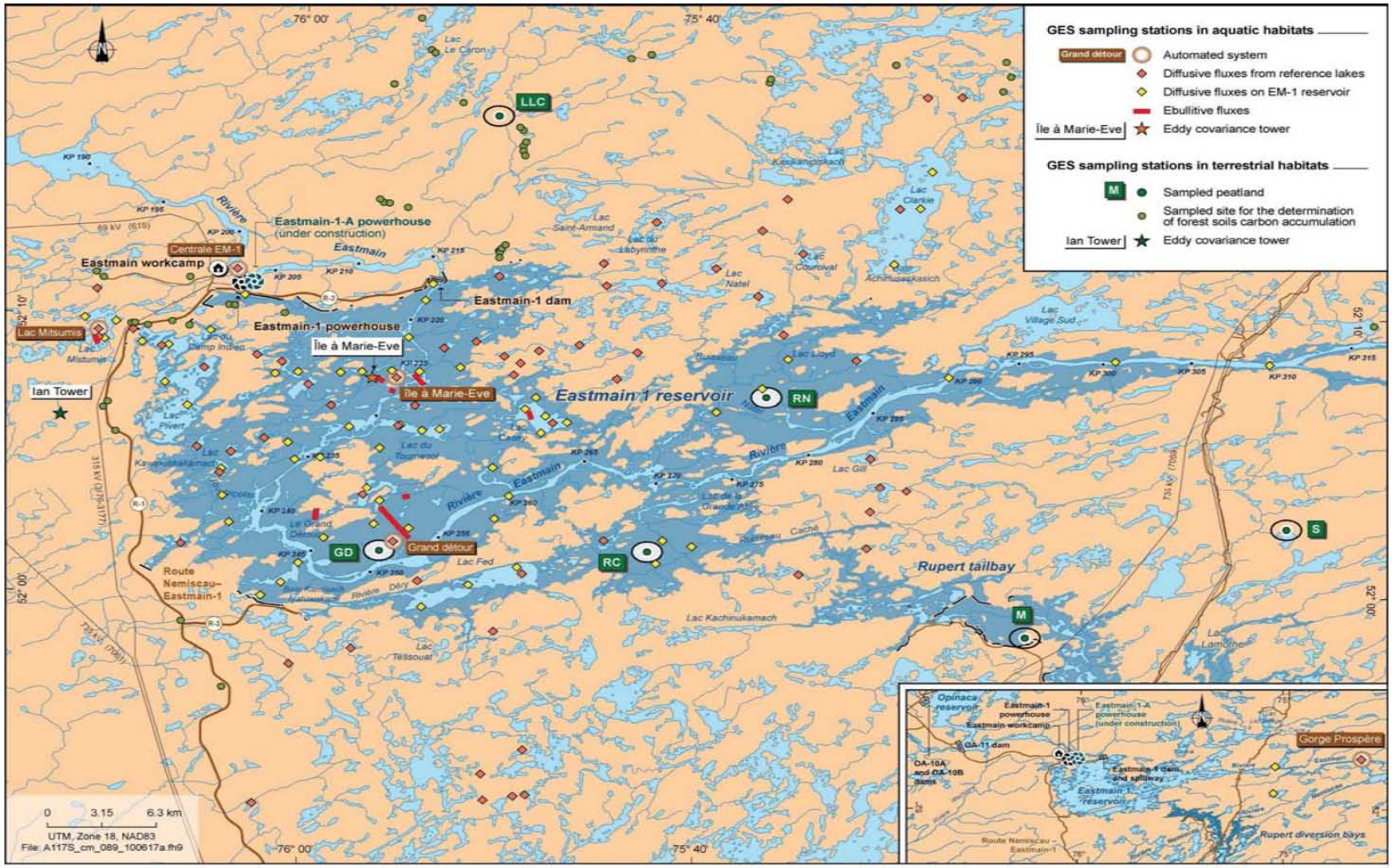


Figure 1 Techniques used to measure aquatic GHG emissions in the Eastmain 1 net GHG emissions project: a floating chamber used from a hydroplane (A) and an automated system installed on a raft (B) for diffusive-emission measurement, plus a schematic of the CH_4 bubble collector (C).

Degassing emissions were measured using a continuous gas monitor installed at the Eastmain-1 powerhouse from September 2006 to December 2009. The advantage of such an instrument is that it provides, with a single sampling station, a robust time series data set that is representative of the whole reservoir (Demarty et al. 2009). In order to estimate degassing fluxes, it was assumed that the concentration of CH_4 and CO_2 in the air was constant, that any gas concentration in the water exceeding that in the air was emitted into the air, and that the difference between both concentrations represents the degassing emissions that take place immediately downstream of the powerhouse. Details on equations and calculations are available in Demarty et al. (2009) or UNESCO-IHA (2009). This is considered to be a conservative estimate of degassing since, under natural conditions, the concentration of CH_4 and CO_2 in water is often oversaturated compared with its concentration in air. Annual overall degassing emissions were estimated by multiplying the monthly mean concentration of CH_4 or CO_2 in the water by the monthly mean water flow and factoring in the monthly mean water temperature, as temperature affects gas solubility in water.

Bubble emissions of CH_4 were measured using bubble traps submerged (inverted funnels) at 30 cm beneath the water surface (Figure 1). The accumulated gas was sampled every two to three weeks from early June to late September 2008 and analyzed for CH_4 concentration with a gas chromatograph. A total of 50 funnels were installed along eight transects of 5 to 10 funnels each, covering the four major pre-flooding cover types (forests, peatlands, lake and river) flooded by the Eastmain 1 reservoir (Map 2). One transect was located on Lac Mitsumis, a reference lake. Low CH_4 production was anticipated in the oligotrophic boreal waters studied. To estimate annual overall gross CH_4 bubble emissions from the Eastmain 1 reservoir, the CH_4 bubbling value was multiplied by the surface area of the reservoir, using 1% of 603 km^2 for the lower limit of the extrapolated results, 5% for the mean value and 10% for the upper limit.

The carbon sink at the bottom of the Eastmain 1 reservoir, was estimated from 14 sedimentation traps installed at various locations within the reservoir from early June to the end of September in 2008 and from 24 sedimentation traps installed in 2009 (Figure 2). The natural variability in lakes was estimated from both sediment cores and sedimentation trap data collected from 11 various-size lakes located in the immediate vicinity of the reservoir. Details on these techniques can be found in Teodoru et al. (2010). The mean value of the carbon storage corresponds to the area-weighted averages from high sedimentation stations (5) and low sedimentation stations (9). The lower limit corresponds to the lowest carbon accumulation in sedimentation traps and the upper limit, to the highest accumulation rates.



Map 2: Example of the sampling stations location in the Eastmain 1 area (Québec, Canada) for diffusive and bubble emission measurements. Degassing emissions were measured at Eastmain-1 powerhouse. Diffusive emissions were also measured with automated systems and an eddy covariance system. Terrestrial fluxes were measured with eddy covariance and chamber techniques.

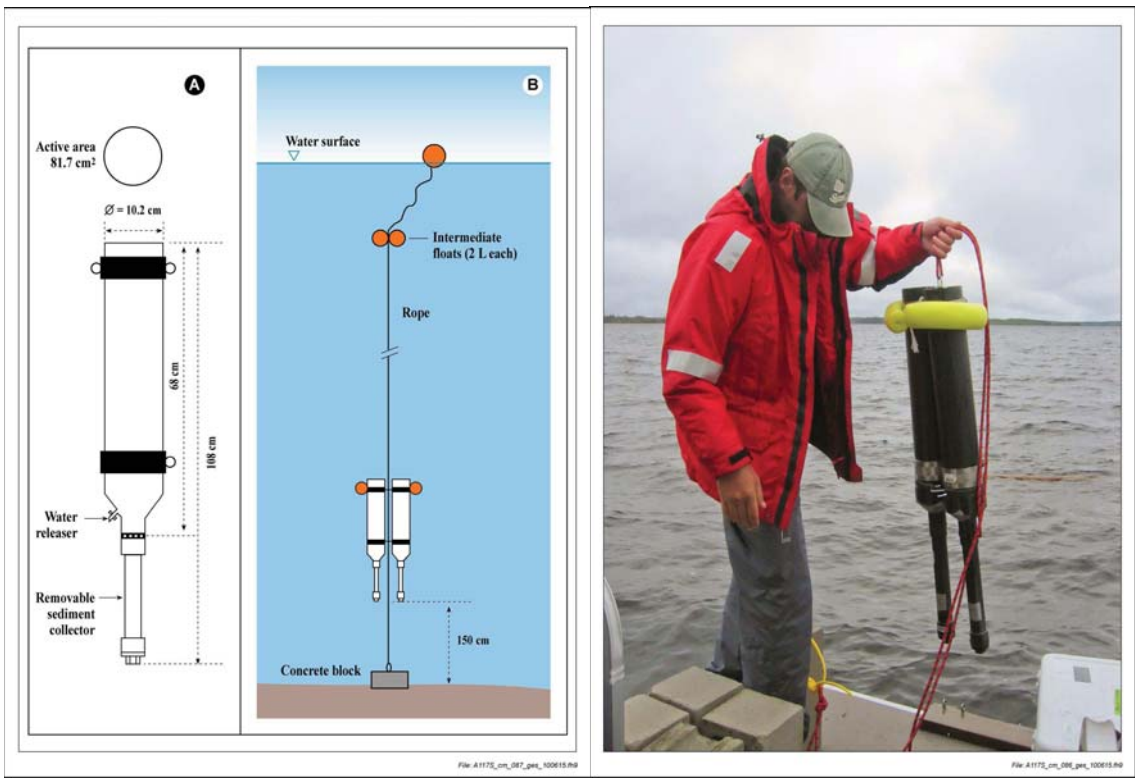


Figure 2 Picture and schematic of a sedimentation trap used in the Eastmain 1 net emissions project to estimate the carbon sink at the bottom of the Eastmain 1 reservoir (Teodoru et al. 2010).

2.3 TERRESTRIAL FLUX MEASUREMENTS AND CALCULATION

The natural terrestrial ecosystem is divided into two main categories: wetlands and forests. The forest can be divided into three types: coniferous forest represents the largest surface area, with 167 km^2 or 49% of the total terrestrial surface area, while deciduous forest and burned forest respectively represent 16 km^2 and 114 km^2, and 5% and 33% of the surface area. Wetlands can be separated into three types: bogs represent 85 km^2 or 14% of the total terrestrial surface area, and fens and wetlands-marsh-swamps respectively represent 1 km^2 and 25 km^2, and 0.2% and 4% of the surface area. The rest of the terrestrial surface area is occupied by bare soils that represent 46 km^2 or 8% of the terrestrial surface area. No emissions were calculated from bare areas.

2.3.1 Forest

Forest CO_2 fluxes were estimated based on the net ecosystem exchange (NEE) measured from August 2006 in a mature and regionally representative black spruce forest (closed canopy located at Ian's Tower on Map 2 and Figure 3) using eddy covariance (Figure 5). Net CO_2 fluxes were measured 10 times per sec (10 Hz, 5 Hz during winter) and 30-minute averages were used in subsequent processing of the data. After quality control, gaps in the data were filled in using different techniques, taking into account ecosystem respiration, photosynthetically active radiation (PAR), soil temperature and other parameters. Details on the technique, equations and calculations are available in Baldocchi (2003) and Bonneville et al. (2007). These gap-filling methods are the standard procedures, used by the flux community in applying the eddy covariance technique (e.g. Barr et al. 2004). An overall annual CO_2 budget was calculated by accumulating the NEE over each year of study. Since it is recognized, that the fire cycle is around 100 years, 1% of the landscape, on average, should burn yearly. Therefore, we assumed that about 1% of the total burnable area (coniferous+deciduous+burned area), which represents 3 km^2, would burn every year and that 50% of the related biomass burned would be emitted to the atmosphere as CO_2.

In order to compute the regional coniferous forest CO_2 budget, NEE values measured at Eastmain 1 were combined with literature data from other representative boreal black spruce forests of different ages and jack pine forests. In this way, we could take into account the spatial and temporal variability in NEE for the different coniferous forest types. For deciduous forests, the CO_2 budget was derived from literature data on eddy covariance NEE measurements made in boreal aspen forests. Literature data were used to estimate the CO_2 budget of burned forests.

Forest CH_4 fluxes were estimated from chamber measurements of soil CH_4 fluxes taken in 2007 in regionally representative coniferous, deciduous and burned forest sites in the reservoir surroundings. Fluxes were determined based on linear change in gas concentration from samples collected over a 90-min period and analyzed on a gas chromatograph (Ullah et al. 2009).

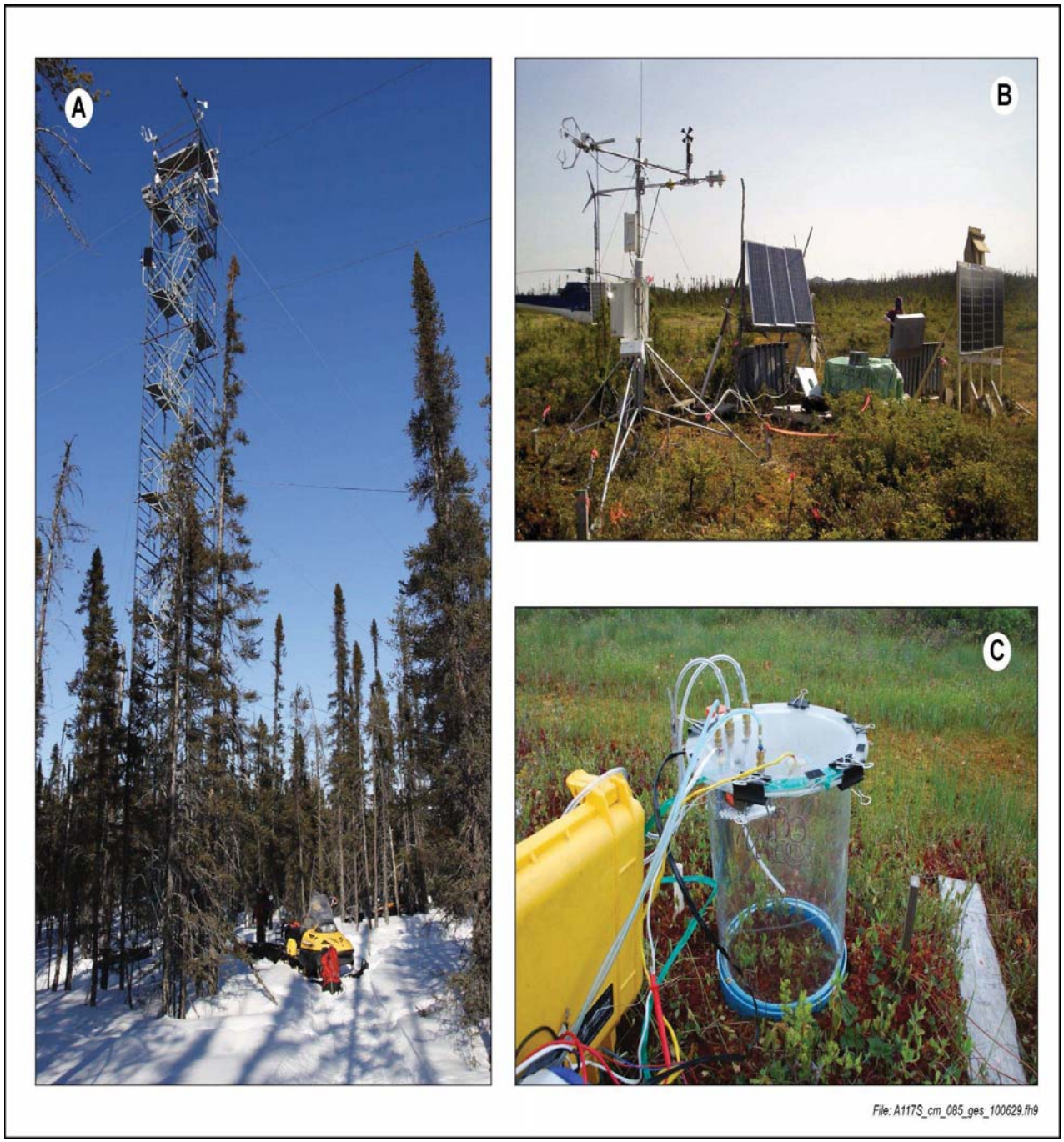


Figure 3 Techniques used to measure terrestrial GHG fluxes in the Eastmain 1 net GHG emissions project: an eddy covariance tower at Ian's Tower site (A) and in the Lac Le Caron peatlands (B), and clear terrestrial chambers (C).

Fluxes of CH_4 were measured six times between June and October 2007. Annual fluxes were estimated by multiplying daily average growing season values by the length of the growing season (determined by eddy covariance tower data) and assuming no winter fluxes. The forest CO_2 and CH_4 budget was calculated as the area-weighted sum of the CH_4 budget for each forest type (coniferous, deciduous and burned).

2.3.2 Wetlands

Peatlands chamber measurements of NEE-CO_2 and CH_4 fluxes were performed in six regionally representative bogs (Figures 3 and 5) between 2005 and 2009, and in fens from 2006 to 2008. Fluxes were measured from five different microforms (high hummocks, low hummocks, hollows, lawns, pools) representative of the spatial heterogeneity of the peatlands. Sampling was done during the growing season (from May to October). Wintertime daily average fluxes were assumed to be 10% of the growing season fluxes (Pelletier et al. 2007, Pelletier 2005). Growing season fluxes, PAR and other parameters were used to estimate overall annual fluxes. Details on the techniques, equations and calculations are available in Pelletier et al. (2009), Pelletier et al. (2007) and Bonneville et al. (2009).

From June 2008 to December 2009, NEE-CO_2 was also measured directly with a portable eddy covariance tower located in the Lac Le Caron peatlands (LLC, Figures 3 and 5). Data processing and annual CO_2 budget calculation were performed similarly to those for the forest data. In summer 2009, a Los Gatos fast-methane analyzer was also used to measure CH_4 fluxes in the Lac Le Caron peatlands with the flux gradient micrometeorological technique (Wagner-Riddle et al. 1996). Continuous CH_4 concentrations measured at 1 Hz were obtained from two heights, and the resulting computed fluxes were averaged over 30 minutes.

The bog CO_2 budget is an average of the fluxes measured for each year from 2006 to 2009 using the chamber data, and the average annual CO_2 budget derived from the flux tower data collected in 2008 and 2009. The fen CO_2 budget was obtained by averaging the chamber fluxes measured in 2006 and 2008. The overall regional wetland CO_2 budget consists of the area-weighted sum of the CO_2 and CH_4 budget for each peatland type (bogs, fens), with swamps/marshes given the average value for all peatlands.

3. RESULTS AND DISCUSSION

According to the IPCC (2006) and UNESCO-IHA (2009) definition, net GHG emissions from a reservoir should be calculated over a 100-year period and for the watershed as a whole. However, to determine net emissions in the present analysis, we only consider the surface area flooded by the creation of the EM-1 reservoir. To calculate net GHG emissions at the Eastmain 1 reservoir, we considered the following elements:

- Bubbles, degassing and diffusive emissions from Eastmain 1 reservoir are direct emissions from the reservoir and are related to reservoir creation.
- Sources of GHG emissions from natural ecosystems (lakes, rivers, streams, forest fire emissions, CH_4 emissions from peatlands) as well as sedimentation in the reservoir) were subtracted from Eastmain 1 reservoir emissions.
- GHG sinks in natural ecosystems (forest and peatland CO_2 sinks) were added to Eastmain 1 reservoir emissions.
- We used the data from natural ecosystems and reservoir data from four years after flooding to predict Eastmain 1 net GHG emissions over 100 years.

As it is very difficult to predict precise values over a long period of time, we are presenting the long-term trends using three different scenarios: mean, lower limit and upper limit scenarios. The first uses the mean net emissions from the reservoir and corresponds to the post-flooding gross carbon emissions minus the area-weighted pre-flooding carbon emissions from the terrestrial and aquatic ecosystems. If the pre-flooding ecosystem was a net sink, then the resulting net reservoir effect will be larger than the gross emissions measured from the reservoir. The lower limit scenario (least net change from pre- to post-flooding, best-case scenario) uses the largest pre-flooding terrestrial carbon emissions (or smallest terrestrial carbon sink), the largest pre-flooding aquatic carbon emissions and the lowest values for diffusive, degassing and bubble emissions from the reservoir. The upper limit scenario (most net change from pre- to post-flooding, worst-case scenario) uses the smallest pre-flooding terrestrial carbon emissions (or largest terrestrial carbon sink), the smallest pre-flooding aquatic carbon emissions and the highest values for diffusive, degassing and bubble emissions from the reservoir. Negative values indicate a sink (absorption) of GHG and positive values indicate a source (emission) of GHG from the ecosystems.

Our results are based on more than 120,000 measurements taken over seven years. The data from natural ecosystems (aquatic and terrestrial ecosystems) showed that the ecosystems to be flooded, including forest fires, were overall a low net source of carbon, with a mean value of about 3,200 tonnes of C-CO_2/year. The forests were net CO_2 sinks for the mean and lower limit scenarios, with values ranging from -27,000 to –12,000 tonnes of C-CO_2/year. The upper limit scenario showed a low carbon sink with a value of 1,200 tonnes

of C-CO_2/year. Peatlands/wetlands ecosystems showed the same trend with a lower sink or source of CO_2, with values of -8,800, -4,200 and 600 tonnes of C-CO_2/year for the lower limit, mean and upper limit scenarios, respectively. However, peatland/wetland were sources of CH_4, with values ranging from 1,350 to 1,850 tonnes of C-CH_4/year. On the other hand, all aquatic ecosystems, including ponds in the peatlands, were a source of CO_2 and CH_4, with values ranging from 525 to 13,300 tonnes of C-CO_2/year and 23 to 102 tonnes of C-CH_4/year. The contribution of streams to the C-CO_2 source in natural aquatic ecosystems is substantial relative to their small total surface area. However, lakes' carbon sedimentation represents a low sink, with values ranging from -250 to -1,255 tonnes of C-CO_2/year.

Net Eastmain 1 emissions are changing over time, starting from very high in the first year (500,000 tonnes of C-CO_2) and decreasing exponentially over the following four years (165,000 tonnes of C-CO_2) for the mean scenario. Eastmain 1 emissions are totally dominated by CO_2 diffusive emissions, which represent more than 99% of total emissions; therefore, degassing and bubbling emissions represent less than 1% of the total. Sedimentation at the bottom of the reservoir is about twice as much as in natural lakes but represents a small fraction of the total flux. CH_4 emissions are very small and represent less than 1% of total emissions.

To predict the evolution of net CO_2 fluxes over 100 years, we calculated the lower limit of gross CO_2 fluxes from measurements taken on older reservoirs (ranging from 12 to 30 years old) in the same boreal region (Caniapiscau, La Grande 1, La Grande 3, La Grande 4, Laforge 1, Opinaca, Robert-Bourassa [Figure 1, Tremblay et al. 2005]) and combined them with the initial Eastmain 1 data to determine the long-term pattern in minimum CO_2 emissions. We further assumed that the difference between upper limit, mean and lower limit values of net CO_2 fluxes estimated for the first four years for Eastmain 1 reservoir will be maintained over time, and on this basis we estimated the potential range in net CO_2 emissions over a 100-year period (Figure 4).

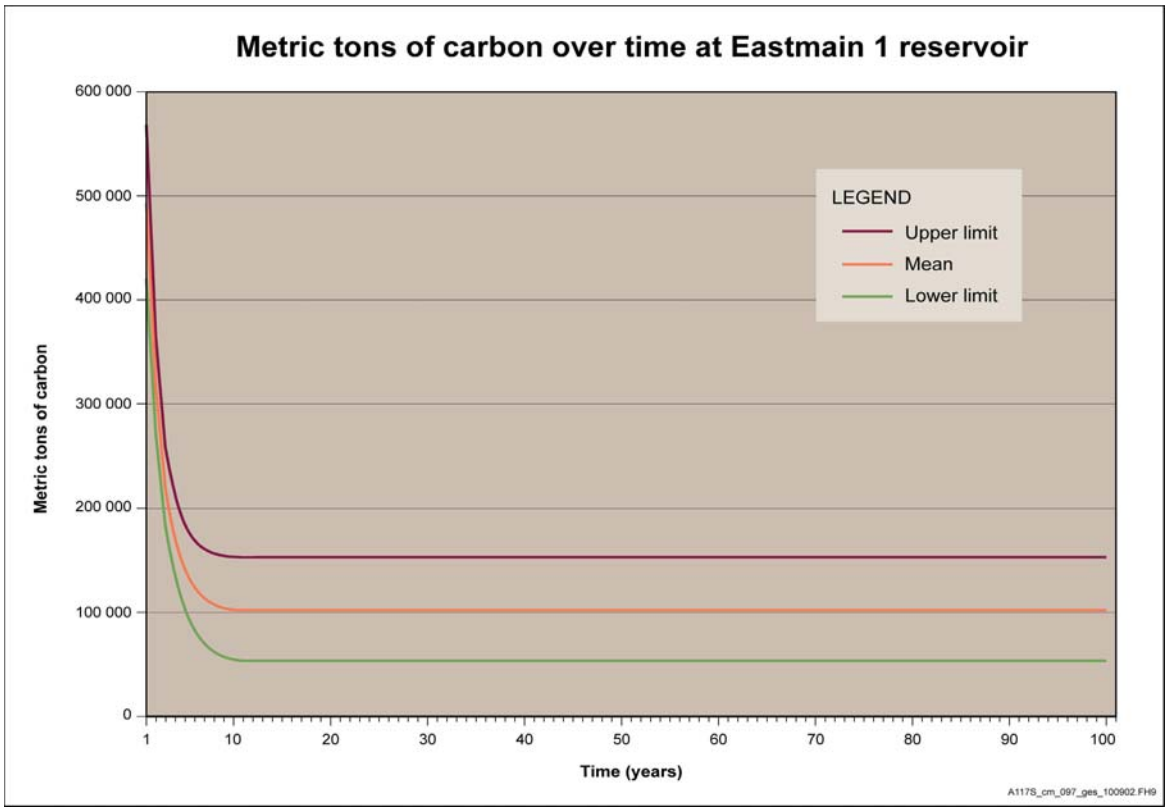


Figure 4: Evolution of Eastmain 1 net emissions (tonnes of carbon) over time (years) for the lower limit (best-case scenario), mean and upper limit (worst-case scenario).

The resulting pattern of decline in reservoir CO_2 emissions with reservoir age is accurately described as a first-order exponential decay, which indicates that after a sharp decrease characteristic of the first five years, net emissions stabilize around a constant value of approximately of 100,000 tonnes of C-CO_2/year. Accordingly, long-term average net emissions correspond to approximately 158,000 tonnes of C-CO_2/year. Considering forest fire, or not, represents only about a 0.2 % difference.

The model of net CO_2 emissions from Eastmain 1 reservoir can be used to estimate the temporal evolution of CO_2 equivalent emissions per unit of energy generated for the reservoir (Figure 5). For energy output of 6.9 TWh/year, net CO_2 eq. emissions per unit of energy generated were initially relatively high, at about 640 tonnes of CO_2 eq./GWh, but these annual emissions quickly decline and are below those from a natural-gas combined-cycle (NGCC) generating station after the initial three years (Tremblay et al. 2005). However, it takes about five years for the accumulated CO_2 eq. emissions to fall below the NGCC value (Figure 6). Our model further predicts that these net emissions should stabilize at around 54 tonnes of CO_2 eq./GWh after 10 years, and stay roughly constant at that level thereafter for the mean scenario.

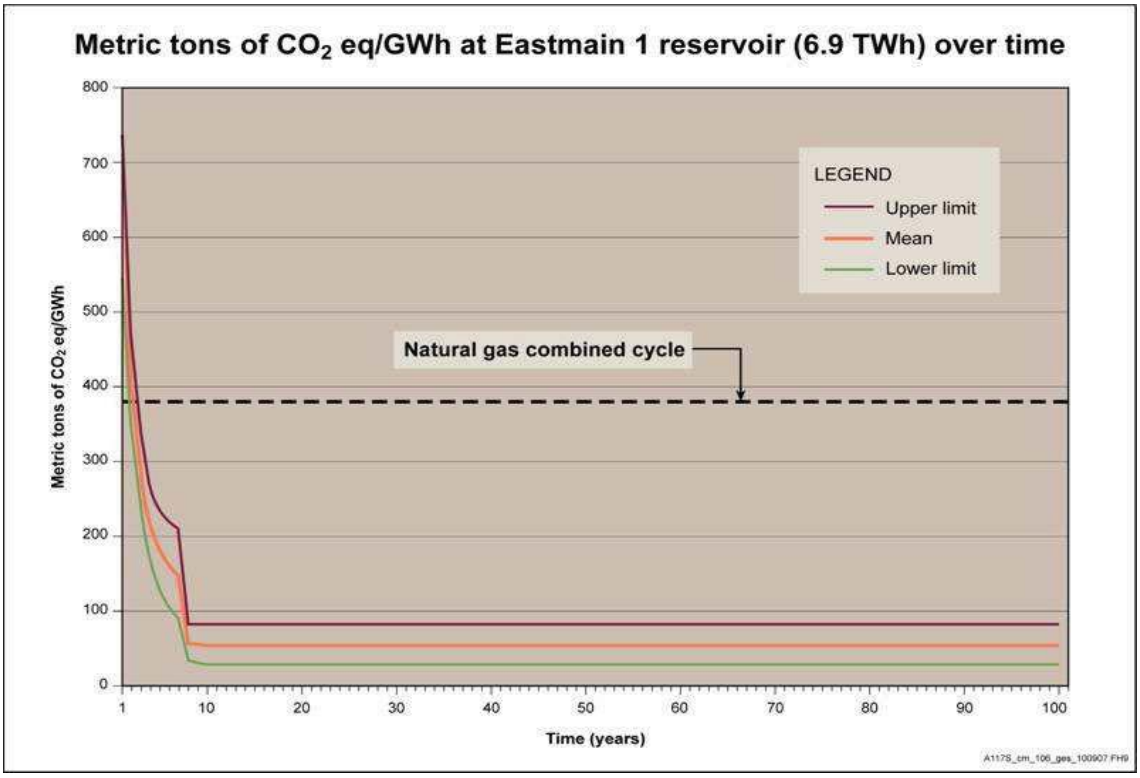


Figure 5: Evolution of net emissions per unit of energy generated (tonnes of CO_2 equivalent/GWh over time [years]) for Eastmain-1 powerhouse (6.9 TWh) and a natural-gas combined-cycle power station (NGCC, 6.9 TWh, 380,000 tonnes CO_2 eq./ TWh). The drop in the curves at year 7 is related to the addition of the energy generated from the EM-1A power plant.

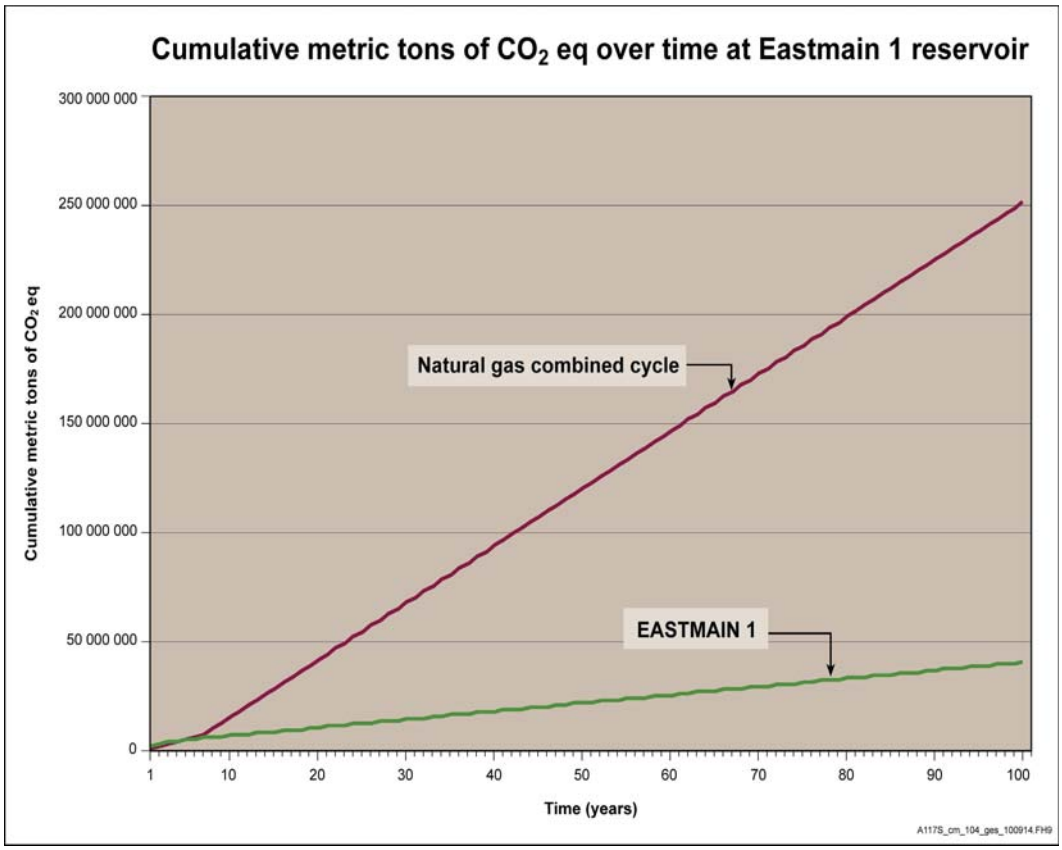


Figure 6: Cumulative net GHG emissions per unit of energy generated (tonnes of CO_2 equivalent/GWh over time [years]) for Eastmain-1 powerhouse (6.9 TWh) and a natural-gas combined-cycle power station (NGCC, 6.9 TWh, 380,000 tonnes CO_2 eq./ TWh).

4. CONCLUSIONS

Our study has shown that natural ecosystems to be flooded were overall a low net source of carbon. Net GHG emissions are substantial in the first years after flooding and decrease rapidly, stabilizing after about 10 years. This study also clearly indicates that CH_4 emissions, degassing and bubbling emissions are not significant in terms of net GHG emissions from Eastmain 1 and that they are probably not an issue in most boreal reservoirs.

With a relatively small surface area and a very short water residence time, for an installed capacity of about 1,250 MW, Eastmain 1 reservoir is a good example of a project emitting small amounts of GHGs. The most efficient thermal power plants, natural-gas combined-cycle, emit about 380,000 tonnes of CO_2 equivalent per TWh (Tremblay et al. 2005), whereas Eastmain 1 reservoir emits 16% of this amount over a 100 year. If the results are extrapolated to the entire

watershed, net emissions from Eastmain 1 would be even lower. These results clearly indicate that boreal hydroelectric reservoirs are low GHG emitters. Boreal hydropower plants should therefore be considered part of the solution to reduce the impact on climate change.

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Exhibit No. NPT-208

Advanced Technology Materials

- Summary of HVDC Transmission
- Information Regarding Fiber Optic Cable: Optical Ground Wire Cable
- Description of Aluminum Conductor, Steel Supported (ACSS)
- Description of LIDAR Technology
- Articles Regarding Aerial Laser Survey Technology (LIDAR)
- Article Regarding IEC 61850

Short Summary of HVDC Transmission

by

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December 10, 2010

INTRODUCTION

The first commercial HVDC line built in 1954 was a 98 km submarine cable with ground return between the island of Gotland and the Swedish mainland using mercury arc valves.

Thyristors were applied to d.c. transmission in the late 1960's and solid state valves became a reality. In 1969, a contract to GE for the Eel River d.c. link in Canada was awarded as the first application of solid state valves for HVDC transmission. Today, the highest functional d.c. voltage for d.c. transmission is +/- 800 kV in China and India.

WHY USE DC TRANSMISSION?

When converters are used for d.c. transmission in preference to a.c. transmission, it is generally by economic choice driven by one of the following reasons:

1. An overhead d.c. transmission line with its towers can be designed to be less costly per unit of length than an equivalent a.c. line designed to transmit the same level of electric power.
2. DC transmission may be environmentally more acceptable, because of a smaller transmission line profile, and d.c magnetic fields under HVDC overhead lines have similar intensity to the earth's natural magnetic field.
3. Allow asynchronous electrical systems to be connected.
4. Act is a buffer between separated systems such as between Texas and the east and western systems, so that blackouts won't spread.

CONFIGURATIONS

HVDC converters are either thyristor based and are known as line commutated converters (LCC) or the newer technology of voltage sourced converters (VSC) using insulated gate bipole transistors (IGBTs). An electric configuration of an LCC pole is shown in Figure 1 showing three quadrivalves in a 12 pulse valve group.

These are known as "quadrivalves" and are assembled as one valve structure by stacking four valves in series. Since the voltage rating of thyristors is several kV, a 500 kV quadrivalve may have hundreds of individual thyristors connected in series groups of valve or thyristor modules. A quadrivalve for a high voltage converter is mechanically quite tall and may be suspended from the ceiling of the valve hall, especially in locations susceptible to earthquakes.

Substation Configurations

The central equipment of a d.c. substation are the thyristor converters which are usually housed inside a valve hall. Outdoor valves have been applied such as in the Cahora Bassa d.c. transmission line between Mozambique and South Africa. Figure 2 shows an example of the electrical equipment required for a d.c. substation. In this example, two poles are represented which is the usual case and is known as the "bipole" configuration. Some d.c. cable systems only have one pole or "monopole" configuration and may either use the ground as a return path when permitted or use an additional cable to avoid earth currents.

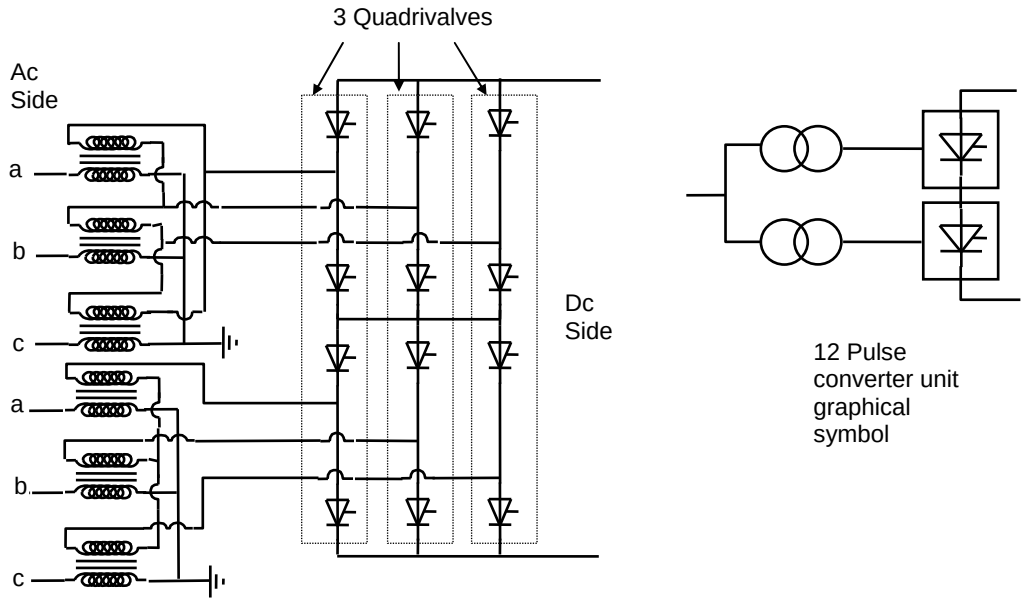

Figure 1. The twelve pulse LCC valve group configuration with two converter transformers. One in star-star connection and the other in star-delta connection

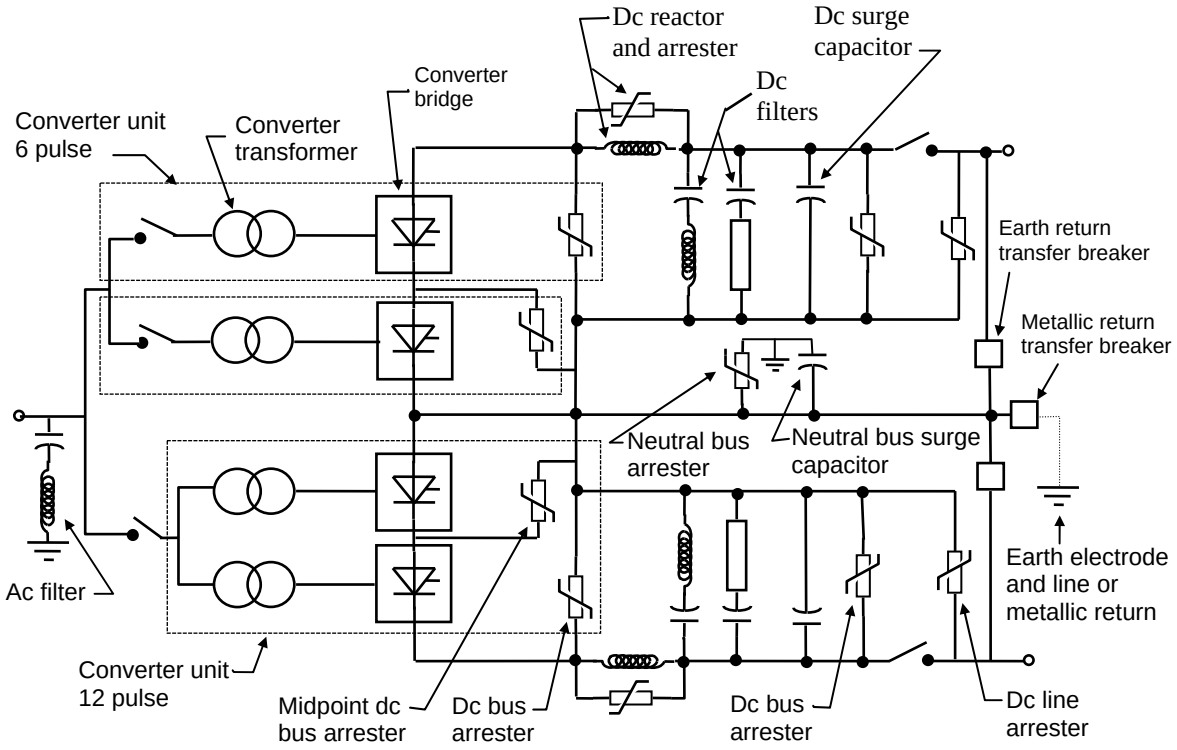

Figure 2: Diagram of equipment in an HVDC substation with LCC converters in a bipolar configuration.

APPLICATIONS OF HVDC CONVERTERS

The first application for HVDC converters was to provide point-to-point electrical power interconnections between asynchronous a.c. power networks. There are other applications which can be met by HVDC converter transmission which include:

1. Interconnections between asynchronous systems. Some continental electric power systems consist of asynchronous networks such as the East, West, Texas and Quebec networks in North America.
2. Deliver energy from remote energy sources.
3. Import electric energy into congested load areas.
4. Increasing the capacity of existing a.c. transmission by conversion to d.c. transmission.
5. Power flow control. Power marketers and system operators may require the power flow control capability provided by HVDC transmission.
6. Stabilization of electric power networks.

HVDC Converter Arrangements

HVDC converter bridges and lines or cables can be arranged into a number of configurations for effective utilization. These are shown in Figure 3 and are as follows:

1. Back-to-Back.
2. Transmission between two substations.
3. Multi-terminal HVDC transmission system.
4. When d.c. transmission is applied right at the point of generation.

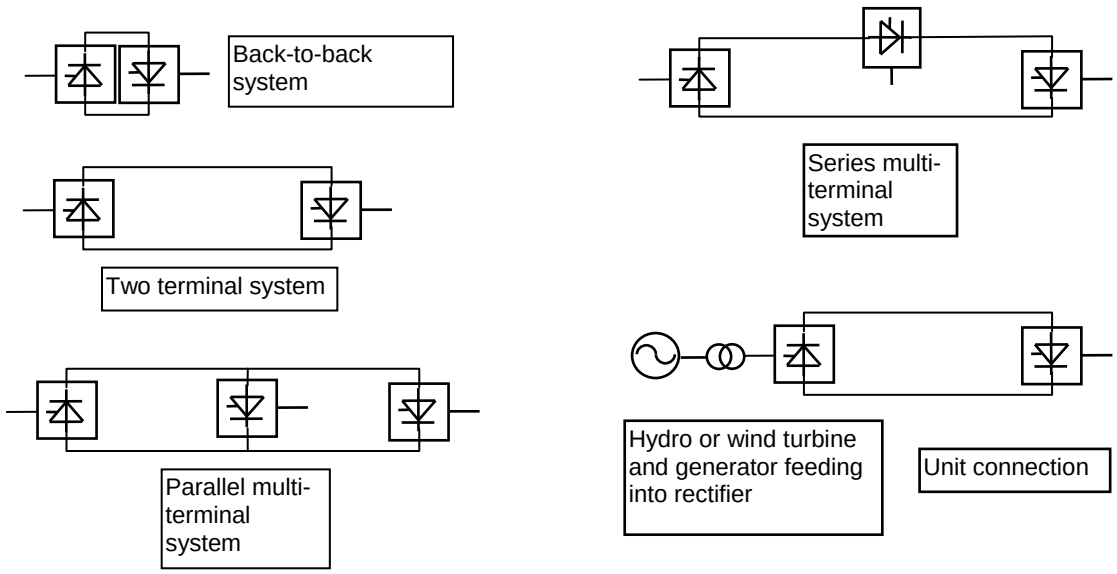

Figure 3: HVDC converter bridge arrangements, which can be used for with both LCC and VSC converters

ENVIRONMENTAL CONSIDERATIONS

Electrical environmental effects that are addressed during a project design include radio interference, audible noise and ozone generation.

Short Circuit Ratio

The strength of the a.c. network at the bus of the HVDC substation can be expressed by the effective short circuit ratio (ESCR). It is used for the ratio between the short circuit level reduced by the reactive power of the shunt capacitor banks and a.c. filters connected to the a.c. bus at 1.0 per-unit voltage and the rated d.c. power. This is more an issue with LCC converters rather than VSC converters.

Lower ESCR means more pronounced interaction between the HVDC substation and the a.c. network, particularly for LCC. A.c. networks can be classified in the following categories according to strength:
Strong systems with high ESCR: ESCR > 3.0
Systems of low ESCR: 3.0 > ESCR > 2.0
Weak systems with very low ESCR: ESCR < 2.0

DC TRANSMISSION WITH VOLTAGE SOURCED CONVERTERS

The special properties of VSC include the ability to independently control real and reactive power at the connection bus to the a.c. system. Reactive power can be either capacitive or inductive and can be controlled to quickly change from one to the other. However, VSC transmission is limited in capacity to about 1000 MW per symmetrical monopole today, but it is anticipate this will increase in the future.

A VSC does not require an active a.c. voltage source to commutate into as does the conventional LCC. The VSC inverter can generate an a.c. three phase voltage and supply electricity to a load as the only source of power. The most recent VSC configuration in its variations now available from all HVDC equipment suppliers is the modular multilevel converter (MMC) as shown in Figure 4 in a “symmetrical” monopole arrangement.

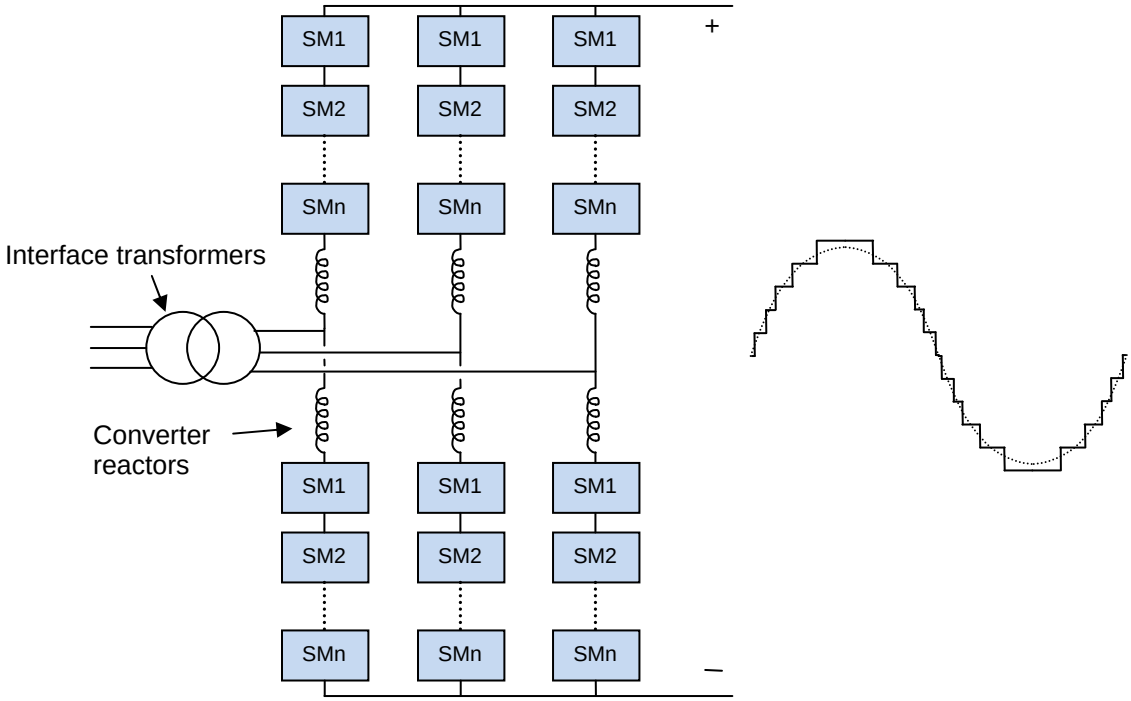

Figure 4: A symmetrical monopole MMC converter made up of sub-modules and the resulting ac voltage wave shape generated by selective switching of the sub-modules.

GROUND OR METALLIC RETURN

HVDC transmission lines at high power ratings greater than 1000 MW are usually configured as bipoles so that during normal operation there is equal current in each pole and no significant ground or metallic return current. When one pole is forced out of service, the HVDC transmission line operates in monopole mode with return current that must flow through the ground or through a metallic return conductor. Metallic return is shown in Figure 5 and ground return is shown in Figure 6. These bipolar configurations can be applied for both LCC and VSC converters.

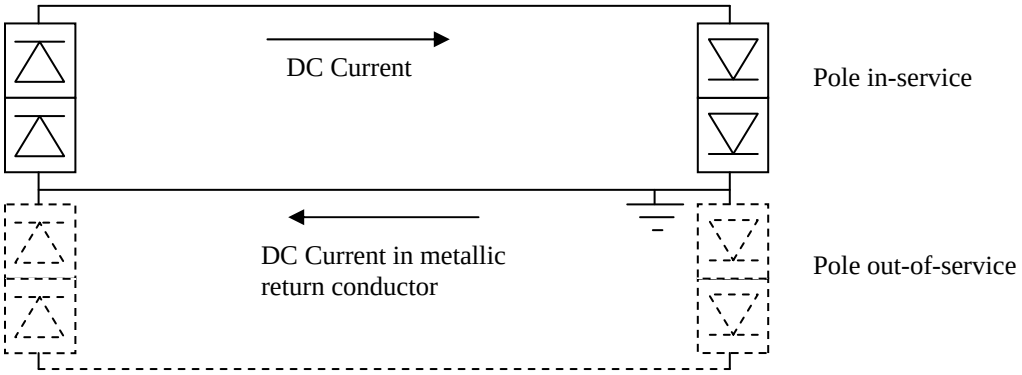

Figure 5: Metallic return conductor when one pole out of service

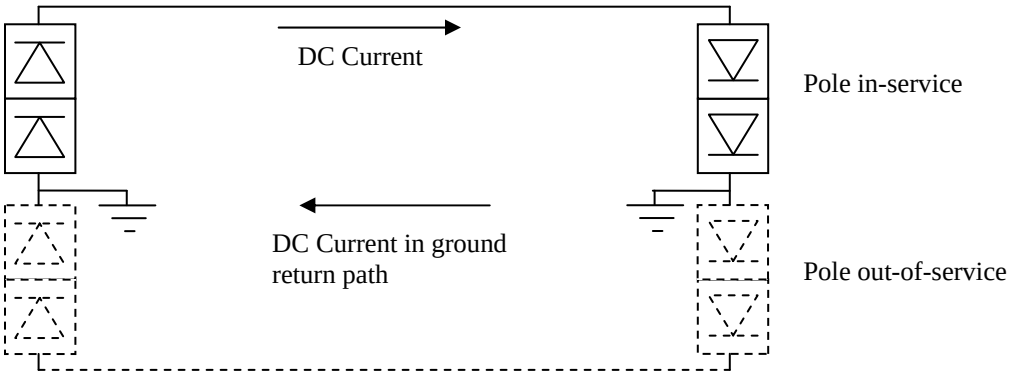

Figure 6: Ground return when one pole out of service

When it is not possible to use ground return for extended use, the IEEE National Electric Safety Code (NESC) can provide a guide. There it is permissible to use ground return for emergency use when one pole of the HVDC transmission line is forced out of service.

FIBER OPTIC CABLE
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- ADSS Hardware
- OPGW Cable
- OPGW Hardware
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Fiber Optic Cable: Optical Ground Wire (OPGW) Cable

Optical Ground Wire (OPGW or OPTGW) is a dual functioning cable that performs the duties of a ground wire - also known as static wire - while providing a path for the transmission of voice, video or data signals by incorporating optical fibers into the design of the cable. AFL Telecommunications is the world's leading supplier of OPGW. Nearly one-third of all OPGW installed worldwide is manufactured by AFL. Our OPGW is ideal for voice, data and video communications and integrates easily into new and established high voltage systems. OPGW is placed at the highest point on power utility structures, allowing for fast, cost-effective installations and extraordinary reliability.

AlumaCore OPGW Cable

AlumaCore Optical Ground Wire is preferred for its performance under the most rugged conditions. Its central aluminum pipe provides superb fiber protection making it ideal for everything from basic installations to those applications requiring high tensions or for extremely long spans.

View Details

CentraCore OPGW Cable

CentraCore Optical Ground Wire is available in fiber counts up to 72, and due to its small size, offers a unique solution to the diameter and weight concerns on many of today's overloaded towers. A central stainless steel tube houses the optical fibers. The stainless steel tube is then inserted into an aluminum pipe which provides added crush protection while increasing the conductivity. The fibers are protected from environmental conditions (lightning, short circuit, loading) to ensure reliability and longevity.

View Details

HexaCore OPGW Cable

HexaCore Optical Ground Wire cable houses and protects the optical fibers within gel-filled stainless steel tubes. Aluminum clad steel and aluminum alloy wires are stranded with the tubes to create a dual-layer design suitable for a variety of applications.

View Details

Slotted Core OPGW Cable

A highly reliable product at an exceptional

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- Related FAQs
- RFQ Checklist [Excel]
- Tech Support

value, Slotted Core Optical Ground Wire is a versatile design suitable for applications ranging from low fiber count, small diameter requirements to high fault current, long span installations.

View Details

Stainless Steel Fiber Optic Tubes

As the inventor and owner of the technology for placing optical fibers into stainless steel tubes, AFL Telecommunications offers a range of tube sizes and fiber counts for a variety of applications. Each tube is flooded with a thixotropic filling compound and hermetically sealed to protect the enclosed fibers from environmental degradation. AFL's stainless steel tubes are suitable for use as a component in aerial applications such as Optical Ground Wire, for buried applications, and for special oil and gas applications. The most common sizes and fiber counts are shown below as the standard offering. For custom sizes, fiber counts or application information, contact customer service.

View Details

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ACSS

Aluminum Conductor, Steel Supported.

APPLICATIONS

ACSS is used for overhead distribution and transmission lines. It is designed to operate continuously at elevated temperatures up to 250°C without loss of strength; it sags less under emergency electrical loadings than ACSR; it is self-damping if prestretched during installation; and its final sags are not affected by long term creep of aluminum. The advantages make ACSS especially useful in reconductoring applications requiring increased current with existing tensions and clearances, new line applications where structures can be economized because of reduced conductor sag, new line applications requiring high emergency loadings, and lines where aeolian vibration is a problem.

SPECIFICATIONS

Southwire's ACSS conductor meets or exceeds the following ASTM specifications:

- B341 Aluminum-Coated Steel Core Wire for Aluminum Conductors, Steel Reinforced.
- B500 Metallic Coated Stranded Steel Core For Aluminum Conductors, Steel Reinforced.
- B609 Aluminum 1350 Round Wire, Annealed and Intermediate Tempers, for Electrical Purposes.
- B802 Zinc-5% Aluminum-Mischmetal Alloy-Coated Steel Core Wire for Aluminum Conductors, Steel Reinforced.
- B803 High-Strength Zinc-5% Aluminum-Mischmetal Alloy-Coated Steel Core Wire for Aluminum and Aluminum-Alloy Conductors, Steel Reinforced.
- B856 Concentric-Lay-Stranded Aluminum Conductors, Coated Steel Supported (ACSS).

The strandings available are identical to those listed in ASTM specification B232.

CONSTRUCTION

ACSS is a composite concentric-lay stranded conductor. Steel strands form the central core of the conductor with one or more layers of aluminum 1350-0 wire stranded around it. The steel core carries most or all of the mechanical load of the conductor due to the "0" (fully annealed or soft) temper aluminum. Steel core wires are protected from corrosion by galvanizing, aluminizing, or mischmetal alloy coating. Corrosion protection should be selected to suit the environment to which the conductor will be exposed. High strength steel core is also available.

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One Southwire Drive
Carrollton, Ga. 30119 USA

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ACSS

Code Word	Size (kcmil)	Stranding (Al/St)	Diameter (in)				Weight Per 1000 ft (lb)			Rated Strength		Resistance OHMS/1000 ft		Ampacity at 200°C (AMPS)
			Individual Wires		Steel Core	Complete Cable						DC @ 20°C	AC @ 75°C	
			Al	Steel			Al	Steel	Total	Standard Strength lb	High* Strength lb			
Partridge/ACSS	266.8	26/7	0.1013	0.0788	0.2363	0.642	251.3	115.5	366.8	8880	9730	.0619	.0761	812
Junco/ACSS	266.8	30/7	0.0943	0.0943	0.2829	0.660	251.9	165.5	417.4	11700	13000	.0615	.0756	822
Ostrich/ACSS	300.0	26/7	0.1074	0.0835	0.2506	0.680	282.6	129.9	412.4	10000	10900	.0551	.0677	877
Linnet/ACSS	336.4	26/7	0.1137	0.0885	0.2654	0.720	316.8	145.7	462.5	11200	12300	.0491	.0604	945
Oriole/ACSS	336.4	30/7	0.1059	0.1059	0.3177	0.741	317.6	208.7	526.3	14800	16300	.0488	.0600	957
Brant/ACSS	397.5	24/7	0.1287	0.0858	0.2574	0.772	374.4	137.0	511.4	11000	12100	.0417	.0514	1047
Ibis/ACSS	397.5	26/7	0.1236	0.0962	0.2885	0.783	374.4	172.1	546.5	13000	14200	.0416	.0512	1054
Lark/ACSS	397.5	30/7	0.1151	0.1151	0.3453	0.806	375.3	246.5	621.9	17500	19300	.0413	.0508	1068
Flicker/ACSS	477	24/7	0.1410	0.0940	0.2819	0.846	449.3	164.4	613.6	13000	14200	.0348	.0429	1180
Hawk/ACSS	477	26/7	0.1354	0.1053	0.3160	0.858	449.3	206.5	655.8	15600	17100	.0346	.0427	1188
Hen/ACSS	477	30/7	0.1261	0.1261	0.3783	0.883	450.4	295.9	746.3	21000	22700	.0344	.0424	1204
Parakeet/ACSS	556.5	24/7	0.1523	0.1015	0.3045	0.914	524.1	191.8	715.9	15200	16600	.0298	.0368	1306
Dove/ACSS	556.5	26/7	0.1463	0.1138	0.3413	0.927	524.2	240.9	765.1	18200	19900	.0297	.0366	1315
Eagle/ACSS	556.5	30/7	0.1362	0.1362	0.4086	0.953	525.4	345.2	870.6	24500	26500	.0295	.0363	1331
Peacock/ACSS	605	24/7	0.1588	0.1058	0.3175	0.953	569.8	208.5	778.3	16500	18100	.0274	.0339	1379
Squab/ACSS	605	26/7	0.1525	0.1186	0.3559	0.966	569.8	261.9	831.8	19700	21300	.0273	.0337	1389
Wood Duck/ACSS	605	30/7	0.1420	0.1420	0.4260	0.994	571.2	375.3	946.5	26000	28300	.0271	.0334	1407
Teal/ACSS	605	30/19	0.1420	0.0852	0.4260	0.994	571.2	367.4	938.6	26600	29300	.0272	.0335	1406
Rook/ACSS	636	24/7	0.1628	0.1085	0.3256	0.977	599.0	219.2	818.2	17300	19000	.0261	.0322	1425
Grosbeak/ACSS	636	26/7	0.1564	0.1216	0.3649	0.991	599.0	275.4	874.4	20700	22400	.0260	.0321	1435
Scoter/ACSS	636	30/7	0.1456	0.1456	0.4368	1.019	600.5	394.5	995.0	27400	29700	.0258	.0318	1454
Egret/ACSS	636	30/19	0.1456	0.0874	0.4368	1.019	600.5	386.3	986.8	28000	30900	.0258	.0319	1453
Flamingo/ACSS	666.6	24/7	0.1667	0.1111	0.3333	1.000	627.9	229.7	857.6	18200	19900	.0249	.0308	1470
Gannet/ACSS	666.6	26/7	0.1601	0.1245	0.3736	1.014	627.8	288.6	916.4	21700	23400	.0248	.0306	1480
Stilt/ACSS	715.5	24/7	0.1727	0.1151	0.3453	1.036	673.9	246.5	920.5	19500	21300	.0232	.0287	1540
Starling/ACSS	715.5	26/7	0.1659	0.1290	0.3871	1.051	673.9	309.8	983.7	23300	25200	.0231	.0286	1550
Redwing/ACSS	715.5	30/19	0.1544	0.0927	0.4633	1.081	675.6	434.6	1110.1	30800	34000	.0230	.0284	1570
Cuckoo/ACSS	795	24/7	0.1820	0.1213	0.3640	1.092	748.8	274.0	1022.7	21700	23300	.0209	.0259	1650
Drake/ACSS	795	26/7	0.1749	0.1360	0.4080	1.107	748.8	344.2	1093.0	25900	28000	.0209	.0257	1662
Macaw/ACSS	795	42/7	0.1376	0.0764	0.2293	1.055	748.8	108.7	857.5	11800	12600	.0211	.0262	1621
Tern/ACSS	795	45/7	0.1329	0.0886	0.2658	1.063	748.8	146.1	894.9	14200	15200	.0210	.0263	1618
Condor/ACSS	795	54/7	0.1213	0.1213	0.3640	1.092	748.8	274.0	1022.7	21700	23300	.0209	.0266	1618
Mallard/ACSS	795	30/19	0.1628	0.0977	0.4884	1.139	750.6	482.8	1233.4	34300	37900	.0207	.0255	1683
Ruddy/ACSS	900	45/7	0.1414	0.0943	0.2828	1.131	847.7	165.4	1013.1	15800	17000	.0186	.0233	1755
Canary/ACSS	900	54/7	0.1291	0.1291	0.3873	1.162	847.7	310.1	1157.8	24600	26400	.0184	.0236	1756

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Redbird/ACSS	954	24/7	0.1994	0.1329	0.3987	1.196	898.5	328.7	1227.3	26000	28000	.0174	.0217	1859
Rail/ACSS	954	45/7	0.1456	0.0971	0.2912	1.165	898.5	175.3	1073.9	16700	18000	.0175	.0220	1824
Towhee/ACSS	954	48/7	0.1410	0.1097	0.3290	1.175	898.5	223.7	1122.3	19700	21300	.0175	.0218	1842
Cardinal/ACSS	954	54/7	0.1329	0.1329	0.3987	1.196	898.6	328.7	1227.3	26000	28000	.0174	.0223	1825
Canvasback/ACSS	954	30/19	0.1783	0.1070	0.5350	1.248	900.7	579.4	1480.1	41100	45400	.0172	.0214	1897
Snowbird/ACSS	1033.5	42/7	0.1569	0.0871	0.2614	1.203	973.4	141.3	1114.7	15400	16500	.0162	.0204	1924
Ortolan/ACSS	1033.5	45/7	0.1515	0.1010	0.3031	1.212	973.4	190.0	1163.4	18100	19500	.0162	.0204	1921
Curlew/ACSS	1033.5	54/7	0.1383	0.1383	0.4150	1.245	973.4	356.2	1329.6	28200	30300	.0161	.0206	1924
Bluejay/ACSS	1113	45/7	0.1573	0.1048	0.3145	1.258	1048.3	204.5	1252.8	19500	21100	.0150	.0190	2017
Finch/ACSS	1113	54/19	0.1436	0.0861	0.4307	1.292	1053.4	375.5	1428.9	30400	33200	.0150	.0193	2015
Bunting/ACSS	1192.5	45/7	0.1628	0.1085	0.3256	1.302	1123.2	219.2	1342.4	21400	23500	.0140	.0178	2110
Bittern/ACSS	1272	45/7	0.1681	0.1121	0.3362	1.345	1198.1	233.8	1431.9	22300	24000	.0131	.0167	2200
Pheasant/ACSS	1272	54/19	0.1535	0.0921	0.4604	1.381	1203.9	429.2	1633.0	34100	37300	.0131	.0169	2200
Dipper/ACSS	1351	45/7	0.1733	0.1155	0.3465	1.386	1272.5	248.3	1520.8	23700	25500	.0124	.0158	2289
Martin/ACSS	1351	54/19	0.1582	0.0949	0.4745	1.424	1278.7	455.8	1734.5	36200	39600	.0123	.0160	2288
Bobolink/ACSS	1431	45/7	0.1783	0.1189	0.3566	1.427	1347.8	263.0	1610.8	25100	27000	.0117	.0150	2375
Plover/ACSS	1431	54/19	0.1628	0.0977	0.4884	1.465	1354.4	482.8	1837.2	38400	41900	.0117	.0151	2375
Nuthatch/ACSS	1510	45/7	0.1832	0.1221	0.3664	1.465	1422.2	277.5	1699.8	26500	28100	.0111	.0143	2459
Parrot/ACSS	1510	54/19	0.1672	0.1003	0.5017	1.505	1429.2	509.5	1938.6	40400	44200	.0110	.0144	2460
Ratite/ACSS	1590	42/7	0.1946	0.1081	0.3243	1.492	1497.6	217.4	1715.0	23400	25000	.0105	.0136	2543
Lapwing/ACSS	1590	45/7	0.1880	0.1253	0.3759	1.504	1497.6	292.2	1789.8	27900	29600	.0105	.0136	2543
Falcon/ACSS	1590	54/19	0.1716	0.1030	0.5148	1.544	1504.9	536.5	2041.4	42600	46600	.0105	.0137	2545
Chukar/ACSS	1780	84/19	0.1456	0.0873	0.4367	1.601	1684.7	386.1	2070.8	35400	38200	.0094	.0122	2751
Mockingbird/ACSS	2034.5	72/7	0.1681	0.1121	0.3362	1.681	1925.6	233.7	2159.3	27200	28900	.0083	.0110	2960
Roadrunner/ACSS	2057	76/19	0.1645	0.0768	0.3839	1.700	1946.9	298.3	2245.2	31700	33900	.0082	.0108	2992
Bluebird/ACSS	2156	84/19	0.1602	0.0961	0.4806	1.762	2040.6	467.6	2508.2	42100	45500	.0078	.0103	3106
Kiwi/ACSS	2167	72/7	0.1735	0.1157	0.3470	1.735	2051.0	248.9	2299.9	29000	30800	.0078	.0104	3080
Thrasher/ACSS	2312	76/19	0.1744	0.0814	0.4070	1.802	2188.2	335.3	2523.5	35600	38100	.0073	.0098	3218
Joree/ACSS	2515	76/19	0.1819	0.0849	0.4245	1.880	2380.4	364.7	2745.1	38700	41400	.0067	.0092	3390

Notes:
(1) Data based on a nominal cable manufactured in accordance with ASTM B 856.
(2) Resistance and ampacity based on an aluminum conductivity of 63%, IACS at 20°C, and a steel conductivity of 8% IACS at 20°C.
(3) Ampacity based on a 200°C conductor temperature, 25°C ambient temperature, 2 ft/sec. wind, in sun, with an emissivity of 0.5 and a coefficient of solar absorption of 0.5, at sea level.
(4) Rated strength for standard strength core based on Class A Galfan coated steel core wire in accordance with ASTM B 802.
(5) Rated strength for high strength core based on Class A Galfan coated high strength steel core wire in accordance with B 803.
* Designated by "/HS" (e.g. Drake/ACSS/HS)

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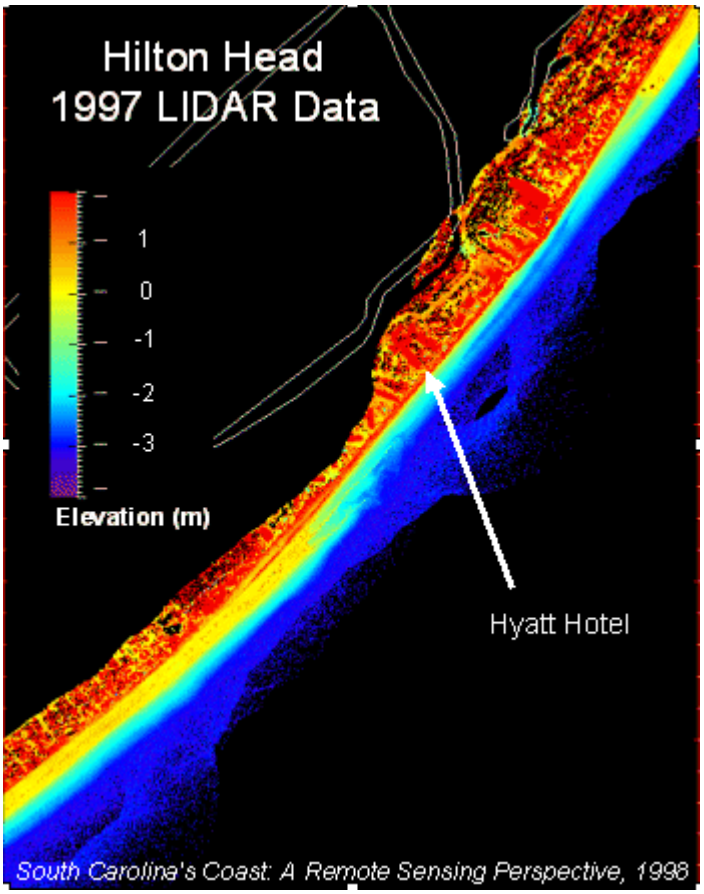
About LIDAR Data

- What Are LIDAR Data?
- How LIDAR Data Are Collected
- Interpreting LIDAR Elevation Maps

What Are LIDAR Data?



Light Detection and Ranging (LIDAR) is a remote sensing system used to collect topographic data. This technology is being used by the National Oceanic and Atmospheric Administration (NOAA) and NASA scientists to document topographic changes along shorelines. These data are collected with aircraft-mounted lasers capable of recording elevation measurements at a rate of 2,000 to 5,000 pulses per second and have a vertical precision of 15 centimeters (6 inches). After a baseline data set has been created, follow-up flights can be used to detect shoreline changes.

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How LIDAR Data Are Collected

For the South Carolina project, a LIDAR sensor was mounted on-board a NOAA DeHavilland Twin Otter aircraft pictured below. Once in flight, the aircraft travels over the beach at approximately 60 meters per second. During the flight, the LIDAR sensor pulses a narrow, high frequency laser beam toward the earth through a port opening in the bottom of the aircraft's fuselage. The LIDAR sensor records the time

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difference between the emission of the laser beam and the return of the reflected laser signal to the aircraft.

NOAA Twin Otter Aircraft

The LIDAR transceiver is rigidly fastened to the aircraft and does not move. However, a scan mirror assembly is mounted beneath the transceiver. A 45-degree folding mirror reflects the laser pulses onto a moving mirror which directs the laser pulses to the earth. The reflected laser light from the ground follows the reverse optical path and is directed into a small Cassegrainian telescope. The moving mirror produces a conical sampling pattern beneath the aircraft over a 30-degree wide swath, thus permitting the collection of topographic information over a strip approximately 300 meters (about 1000 feet) in width from the nominal 600 meter (2000 feet) data collection altitude. For an animated display of the data collection process, click here.

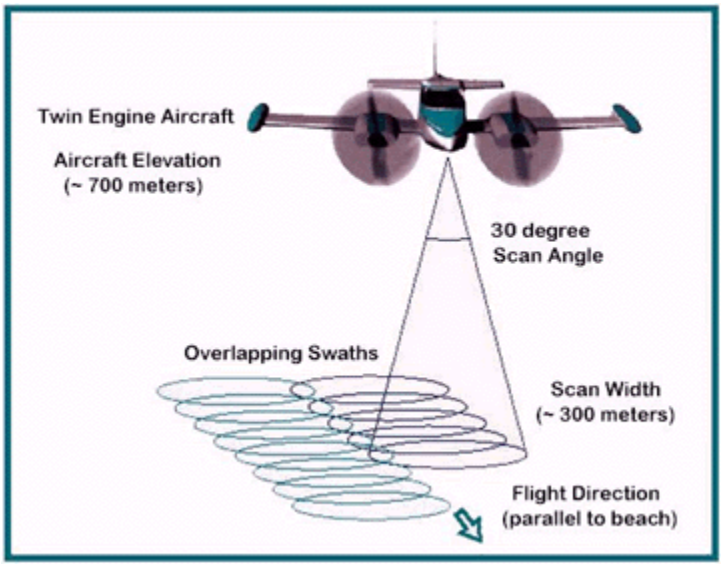

Illustration of How the LIDAR Sensing Instrument Captures Elevation Points.

The LIDAR instruments only collect elevation data. To make these data spatially relevant, the positions of the data points must be known. A high-precision global positioning system (GPS) antenna is mounted on the upper aircraft fuselage. As the LIDAR sensor collects data points, the location of the data are simultaneously recorded by the GPS sensor. After the flight, the data are downloaded and processed using specially designed computer software. The end product is accurate, geographically registered longitude, latitude, and elevation (x,y,z) positions for every data point. These "x,y,z" data points allow the generation of a digital elevation model (DEM) of the ground surface.

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LIDAR data sets on this CD-ROM cover an area from the low water line to the landward base of the sand dunes. Flights are planned to maximize the number of elevation points collected at the lowest tide for the largest area possible. The aircraft flight path is always parallel to the beach. Four passes are flown over each section of the beach. Two of these passes are flown so the center of the swath is over the sand/water interface. The other two passes are flown over the center of the sand/development interface.

Flights generally last four hours. Weather conditions must be monitored. The flights cannot be flown during times of rain or fog as the water vapor in the air could cause the laser beams to scatter and give a false reading. Additionally, the plane cannot fly during times of high winds as the returned laser pulse will not be recorded correctly.

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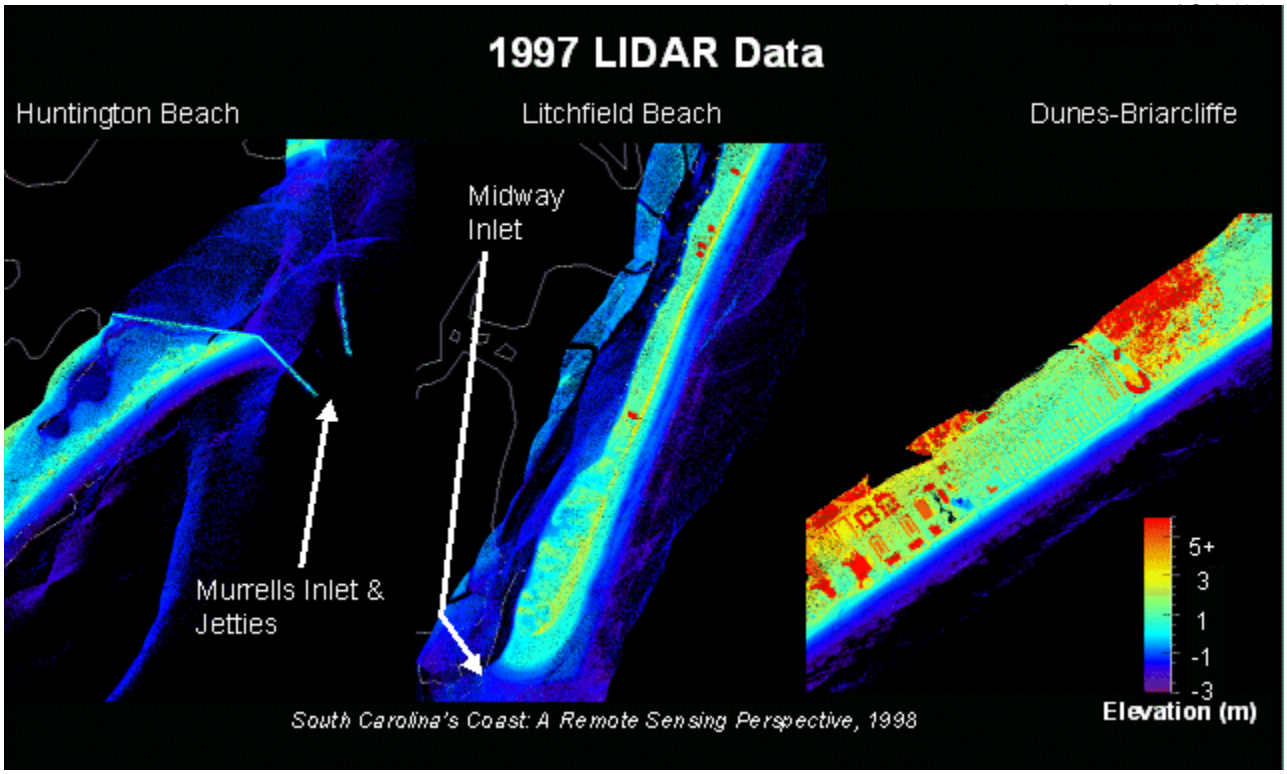
Interpreting LIDAR Elevation Maps

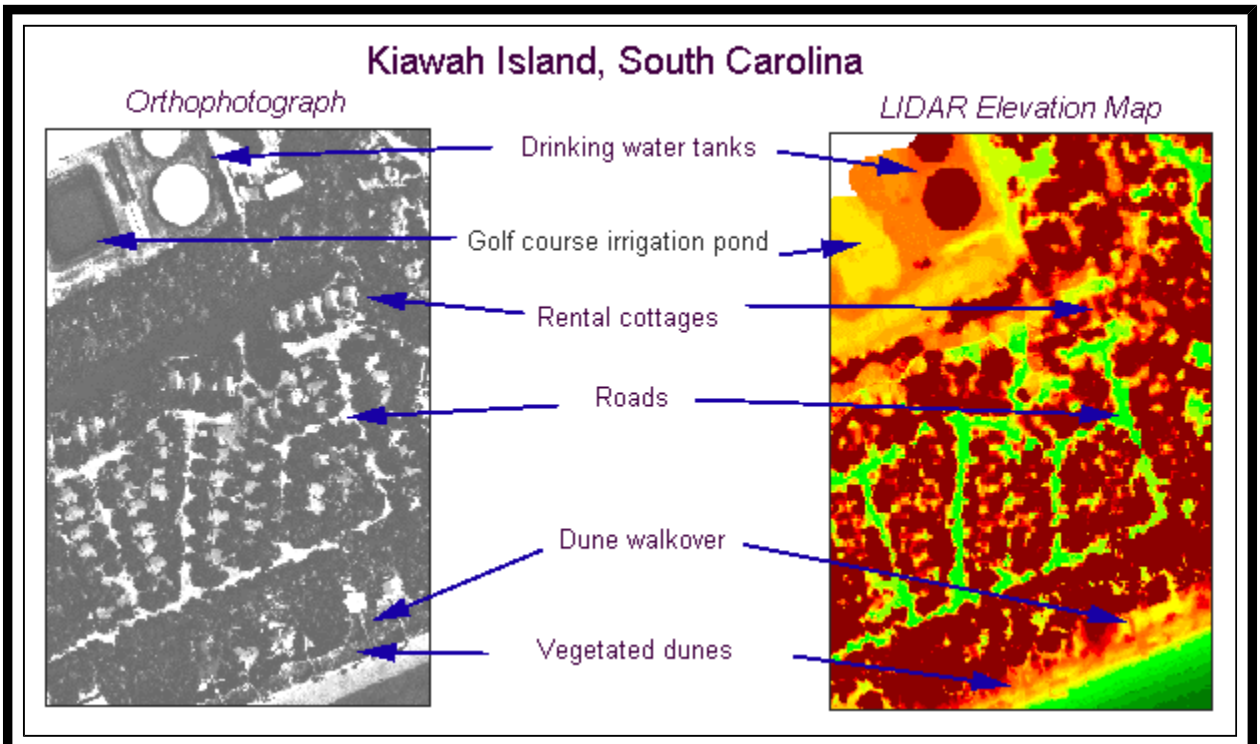
In remote sensing, false color images such as LIDAR elevation maps are common. They serve as an effective means for visualizing data. The term "false color" refers to the fact that these images are not photographs. Rather, they are digital images in which each image pixel represents a data point that is colored according to its value. The purpose of this section is to aid users in interpreting false color images.

LIDAR beach mapping data are composed of elevation measurements of the beach surface and are acquired through aerial topographic surveys. The file format used to capture and store LIDAR data is a simple text file and referred to as "x,y,z," where x is longitude, y is latitude, and z is elevation. Using the elevation "points," LIDAR data may be used to create detailed topographic beach maps.

In the three images shown below, the legend in the bottom right corner of the image has a range of numbers from -3 meters to +5 meters. The numbers indicate the relationship between the colors on the legend and the elevations depicted on the map. For example, in the Huntington Beach map, the deep blue color represents land approximately at sea level or zero elevation. The cyan (light blue) features, like the jetty, represent elevations around 1 meter, or about 3 feet above sea level.



LIDAR data become easier to interpret when examined in conjunction with additional data such as aerial photography. In the example below a LIDAR elevation map is compared with an orthophotograph. This small area on Kiawah Island provides a variety of interesting features. Comparing the orthophoto to the LIDAR data it becomes easier to identify features such as houses, roads, the vegetated dune area, and irrigation ponds.



Comparing Features Found in an Orthophotograph to LIDAR Data

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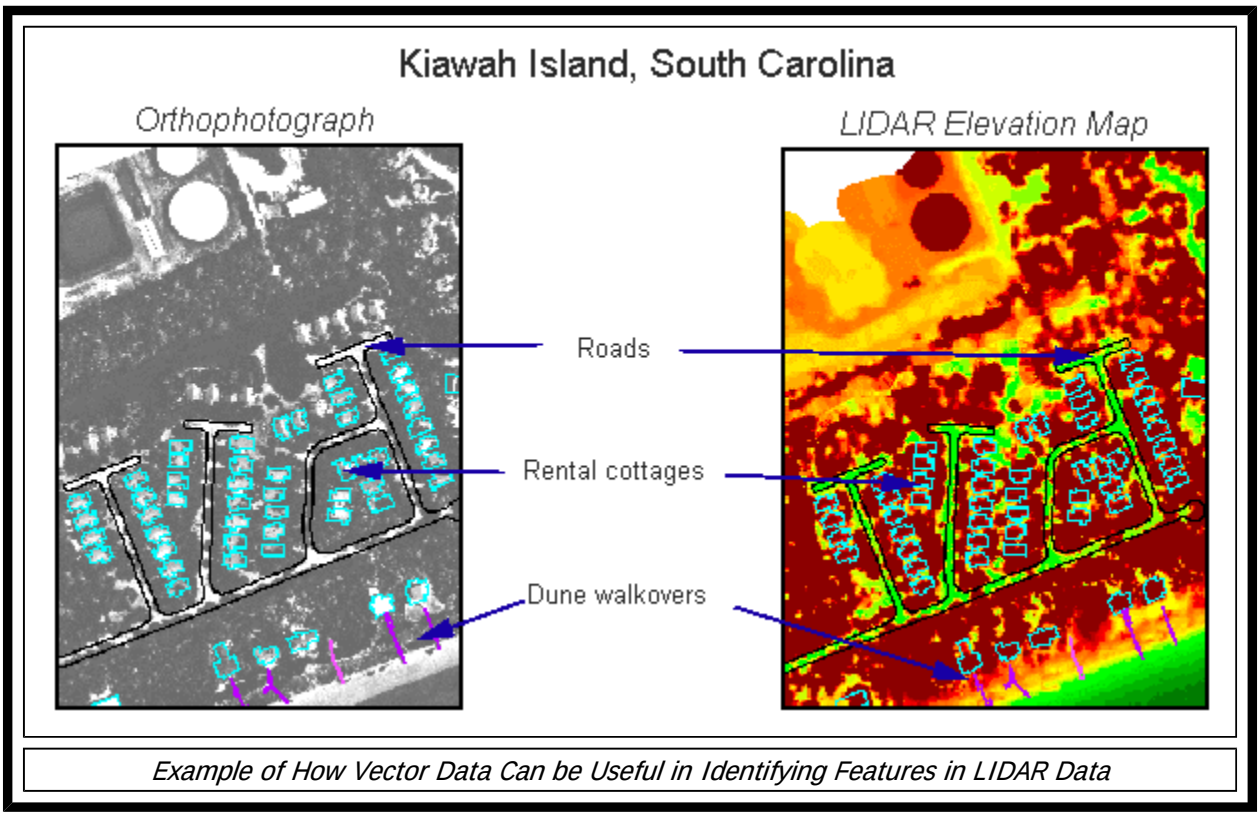
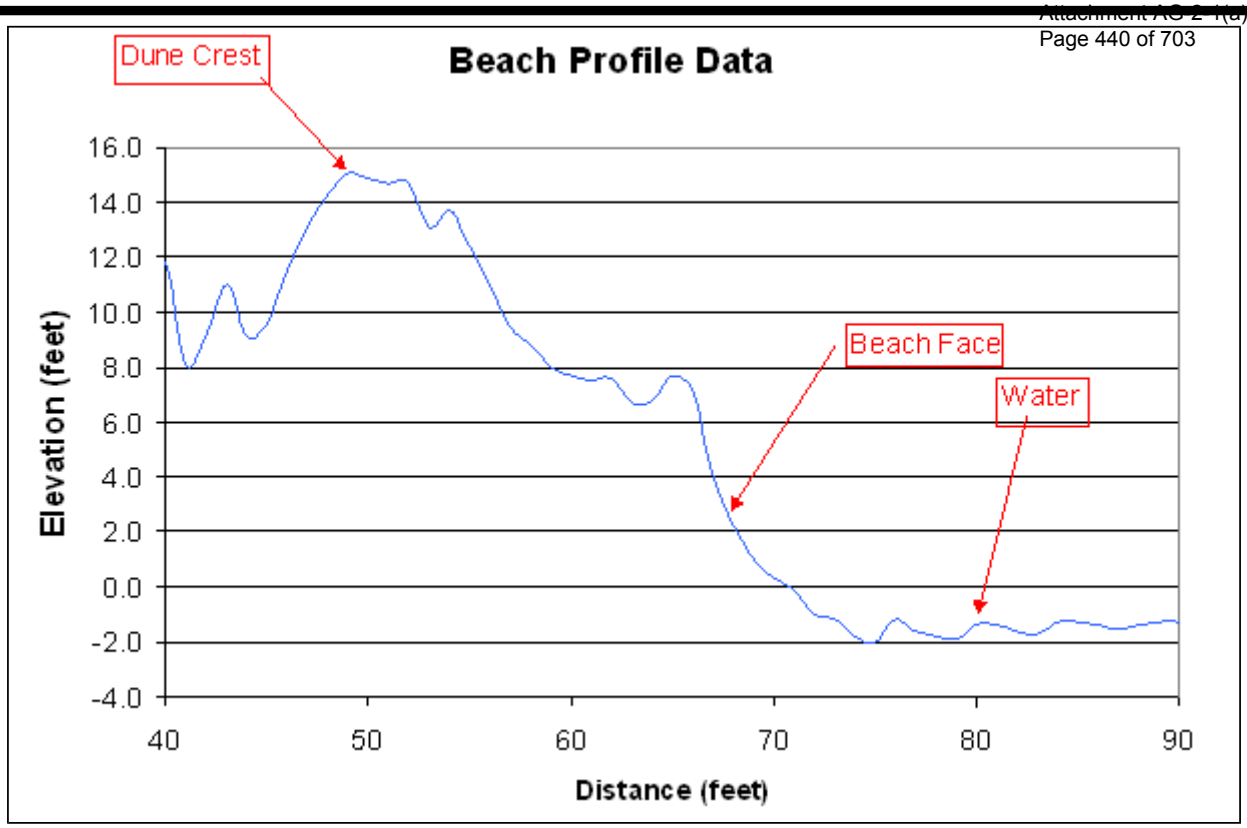
Along the South Carolina coast, beach features tend to be less than 5 meters (16 feet). As a result, the scale of the color bar was chosen to highlight relatively narrow variations in elevation. This legend can be readily viewed in the PDF maps located in the **pdf/islands** directory on this CD-ROM. Addtionally, this legend has been provided for use in ArcView and is located at: **data/lidar/avelev.shp**.

In this second example, an additional vector base map was overlaid on both the orthophoto and LIDAR elevation map. The base map, created in 1993, includes digitized building footprints, dune walkovers, and roads. A detailed base map can assist in confirming features detected by LIDAR elevation measurements. For example, when houses are surrounded by tall vegetation, LIDAR elevation data do not distinguish between roof top and tree top. Without the vector base map, it would be very difficult to determine boundaries between roofs and trees. Often ancillary data do not provide sufficient detail or are not available. In these cases, the user must obtain ground reference information using either local knowledge or by visiting the area to accurately confirm landmarks.



Example of How Vector Data Can be Useful in Identifying Features in LIDAR Data

Users can also view LIDAR data by creating a plot or profile of the data. In the profile below the beach features including the dune crest, beach face, and the water line can be identified. Users that have the add-on ArcView® Spatial Analyst® module can use the LIDAR Data Handler Extension, provided on this CD-ROM, to create similar profiles. For more information about this tool see the Data Tools section.



LIDAR Data Viewed as a Profile

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Monday 27 September 2004

ELECTRIC TRANSMISSION WEEK from the publisher of POWER DAILY

Aerial laser survey technology gives utilities new tool for transmission asset management and planning

Network Mapping Ltd. has devel-oped a technology that links aerial laser mapping with global positioning system data to create incredibly detailed and accurate three-dimensional maps of transmission corridors.

Utilities can use the data generated by these surveys to create and update a precise inventory of transmission assets, as well as for mana- ging existing transmission corridors, planning new transmission lines and calculating the modifications needed to re-rate existing transmission lines to carry more power over them.

Network Mapping is a subsidiary of British firm National Grid Transco. It initially focused on National Grid's electricity and gas system in England and Wales, but has also performed work for National Grid subsidiaries in the United States as well as for utilities in France and Norway.

The company previously mapped all 3,000 miles of National Grid's New England transmission system and has just started a similar project for National Grid's Niagara Mohawk subsidiary in New York. Network Mapping Project Leader Hugh O'Donnell explained that the Niagara Mohawk project is expected to take five years. Initial priority is being given to mapping about 800 miles of the 345-kV system, he said.

O'Donnell explained that the heart of the system consists of a 50-Mhz laser operating in the infrared spectrum and a 6 million pixel digital camera mounted on a helicopter. The helicopter flies over the target corridor at an altitude of 850 to 1,000 feet at 60 to 70 miles per hour.

The data output is prodigious and accurate, O'Donnell said. The laser provides 100,000 3-D data points per second. An hour of flight time results in two gigabytes of laser data as well as seven gigabytes of digital photos. O'Donnell said it takes about 10 hours of computer time to process each hour of data.

In addition, the system correlates very accurately surveyed ground-based GPS reference points with the helicopter-based GPS to determine the precise location of the helicopter at all times. Network Mapping states that its data is accurate to within inches.

Identifying additional line capacity

The processed data is entered into PLS-CADD, the industry standard software for transmission line planning and design. The client receives a detailed plan view of the corridor consisting of a digital photo with all transmission structures identified as well as other major corridor features such as trees, structures and any paths or roads that intersect or cross the corridor.

This information is also presented in elevation form, showing topography and vegetation.

In addition, with the data in PLS-CADD format, the utility can easily run simulations to see how different weather and load conditions affect line sag. Although a utility may have extensive records of its system "as designed," a survey by Network Mapping will record the system as actually built, and provide data for the entire system in a uniform PLS-CADD format.

Mark Browne, manager of transmission line engineering for National Grid US, noted that line ratings are typically restricted by ground clearance. The laser can verify the exact ground clearance at known load and weather conditions.

Browne said the utility can then use PLS-CADD to model increased load and determine exactly what remediation, such as vegetation management, conductor over-tensioning or suspension clamp offset, would be required.

Network Mapping states that on average, up to 10% additional capacity can be realized on a circuit following minor remedial work.

The detailed mapping data also provides benefits for transmission planning. For example, once a corridor is surveyed, different tower configurations and routing can be easily modeled. Furthermore, the data allows the utility to create a virtual 3-D image of a proposed line and potentially could even show the view of the line from any affected property in the survey area.

O'Donnell said that next year, the system will get a new laser generator that will emit more pulses per second and allow the helicopter to fly faster without degrading data quality. In addition, there are plans for multi-spectral imaging. He said this would allow the identification of individual tree species in the corridor so that the faster-growing species can be specifically targeted. SM

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Evolution of Aerial LiDAR Surveys for Electric Transmission ROW: It's Not Just About Points, It's All About Deriving Business Intelligence.

Posted By Editor On September 19, 2010 @ 4:42 pm In E-Letter | No Comments

In light of regulatory requirements and the challenges to effectively manage transmission lines, assess risk of potential problems and identify hazards which could impact reliability, endanger infrastructure, the surrounding environment and community, electric utilities need the highest level of situational awareness and geospatial information in order to address these issues effectively.

Organizations with the public trust to deliver reliable sources of energy and protect the environment, lives and livelihood require more than geospatial information …they require business intelligence that goes beyond geospatial information but to actionable intelligence.

For several years, aerial Light Detection and Ranging (LiDAR) and imagery surveys have been acknowledged as the

Imminent grow-in, fall-in, and clearance conditions
reports are provided electronically usually within
72 hours rather than weeks or months.

most efficient and cost-effective means to create accurate digital elevation and terrain data. Most utilities recognize their value in vegetation management and for engineering surveys. However, all LiDAR surveys are not created equal and a greater wealth of geospatial features and intelligence can be gleaned from these LiDAR and imagery surveys which can provide greater value in actionable business intelligence decision makers need in the office, on the desktop, or in the field.

Aerial LiDAR Imaging surveys for electric utilities are evolving: Not all deliverables are equal or as useful, and what's an electric utility to do with a billion points and a million images? This article will examine why all LiDAR Imaging data are not created equal and discuss the creation and web delivery, in hours or days instead of months, of valuable timely and actionable business intelligence.

Business Intelligence Requires Highest Quality, Accurate Geospatial Data
The creation of critical business intelligence requires a foundation of superior, high accuracy geospatial and survey data and nothing provides higher accuracy, greater resolution, finer detail than aerial LiDAR imaging surveys, generating an accurate, detailed, 3D, digital record of infrastructure, assets and the natural environment.

In addition to highly accurate ortho imagery and terrain data, aerial LiDAR and imagery surveys are able to create valuable geospatial information such as urban/forested terrain, agricultural lands, pervious/impervious surfaces and wetlands. Additional geospatial features such as building footprint, height and structural characteristics; vegetation type, height and density; and, natural and cultural land-use and cover information.

In the right hands, LiDAR surveys are able to provide evidence to show utilities are in compliance with federal and state regulators and NERC standard FAC-003. Accurate as-built data of the entire ROW including structures, facilities, vegetation and incursions derived from the LiDAR data is valuable to transmission engineering in optimizing asset utilization and operational improvements. However, it is very important to keep in mind …Not all LiDAR data is created equal

TCOR LiDAR Imaging Acquisition Systems
GeoDigital International (GeoDigital), Lompoc, Ca and Hamilton, Ontario, Canada, the leader in aerial LiDAR/Imaging surveys for electric utilities, developed the TCOR data acquisition systems designed to meet the precision survey requirements of electrical utilities and engineering companies undertaking construction, re-rating, vegetation and asset mapping projects. TCOR's patented technology provides the capability to acquire stabilized high-resolution LiDAR data, Ortho-images and high resolution oblique images of every structure and every inch of vegetation along a power-line corridor in a single flight pass, reducing acquisition and processing time.

The TCOR system is unique due to its stabilized gimbal platform which corrects for the movement of the aircraft and provides smooth clean coverage of the right of way (ROW). This means more consistent, higher density LiDAR point coverage and the industry's best images. The orientation data is determined 3,600 times per second and is used in real time to stabilize the LiDAR and camera systems such that they remain stable and vertical to an angular accuracy of a few micro-radians, which corresponds to a jitter of less than 5mm at

a 300 meter flying height. The initial acquisition of data results in a complete 3-D model of the ROW, structures and vegetation.

Feature Classification

LiDAR 3-D Right of Way Model with features classified

Unique to GeoDigital's implementation is the ability to accurately geo-reference and spatially map in three dimensions very high resolution digital and multi spectral imagery acquired simultaneously with the laser data. The ortho imagery has a resolution of typically 5 to 10 cm and can be loaded directly into PLS-CADD and draped over the terrain model to visualize the power line corridor. Oblique imagery of the structures and every point within the right of way is acquired with a resolution of 2 to 5cm. This imagery can be directly accessed at any time from within PLS-CADD or a Corporate GIS using GeoDigital's LinearVision Viewer™. The ortho and oblique imagery is fully stabilized and spatially aligned at the pixel level with the LiDAR returns to a very high degree of accuracy.

"The generation of geospatial features is greatly facilitated by simultaneous LIDAR and multispectral image acquisition, saving up to 50% in acquisition costs," said Alastair Jenkins, president and CEO of GeoDigital. "But, the real value is that each surface point possesses an accurate spectral signature assigned to its location, allowing the accurate classification of features."

"Measurement overlap and optimal coverage of high-density LiDAR point-clouds provide a number of distinct advantages such as the ability to detect small linear-type objects and effectively identify transmission lines," added Jenkins. "The LiDAR point cloud data allows the classification and vectorization of the data into detailed, accurate three dimensional information of transmission lines such as vegetation clearances, hazardous trees, vegetation encroachments, as well as pylon positions, cable fixations, attachment points, pylon center lines, lower cross arm edges, and line sag."

Sophisticated data processing and algorithms
By fully leveraging the power of these 3-D datasets, GeoDigital is able to evolve geospatial information into actionable business intelligence. Utilizing advanced biometrics and feature extraction algorithms, their patented ForestSense™ software is able to quantify vegetation attributes such as tree volumes, height, density, confer vs. deciduous, and much more. The data is further enhanced by GeoDigital's segmentation algorithms which automatically classify data and group into treatment units based upon client defined parameters. For example, clients can view treatment statistics such as acres of mowing, herbicide or cut/harvest areas at the span level or summarized for the entire project area created by their own definitions of these treatment types. No longer do utility forester and contractors need to "guess" about the quantity of a particular type of work in a given area. Better Data equals Better Decisions. That is the power of turning 3-D LiDAR and geospatial data into business intelligence.

The creation of critical business intelligence requires a foundation of superior, high accuracy geospatial and survey data and nothing provides higher accuracy, greater resolution, finer detail than aerial LiDAR imaging surveys, generating an accurate, detailed, 3D, digital record of infrastructure, assets and the natural environment.

Grid^Intel Online (GIO) – Online actionable business intelligence, available in hours or days instead of months!
What really distinguishes LiDAR service providers is their ability to provide solutions that enable utilities to manage their right-of-way assets and features, from structures to crossings to vegetation, all from the desktop. GeoDigital has pushed the evolution of billions of LiDAR points and millions of ortho image, to geospatial data, then to geospatial information. Now with GIO, GeoDigital has evolved beyond geospatial information to actionable business intelligence.

GIO is a secure web-based mapping and data management system providing immediate, enterprise-wide access to valuable data through a standard browser. It allows viewing of aerial images, GIS data, emergent conditions, and LiDAR and includes a work management dispatch and tracking tool for emergent conditions.

Critical wire conditions
GeoDigital provides intelligence utilities need to maintain their rights-of-way in a manner unparalleled in the industry today. Their Rapid Clearance reports allow utility vegetation managers and foresters to dispatch crews for remediation of reported conditions that could result in fines up to $1M, providing critical intelligence about wire conditions: At Survey Wire Condition; Max Sag Clearances; Blow-out Condition; Blow-out – max sag Comparison; Hard Clearance Analysis; and Hard Clearance Specifications.

The GIO solution includes Multi Year Audits: Annual routine re-flights performed at significantly lower cost than the initial flights provide imminent grow-in, fall-in, and clearance conditions reports electronically usually within 72 hours. New encroachments and access restrictions are identified, and vegetation work from the previous year can be audited for missed or non conforming work. Cycle work (floor or side trimming) can be scheduled based on vegetation conditions such as height, density, conifer vs. deciduous and distance from line. Identification of issues occurs not only at survey conditions, but at max sag and blow out conditions.

Change detection from multi year audits is an effective and an evolving best practice undertaken by leaders in Transmission Vegetation Management Programs (TVMP). It identifies areas cleared by contractors but also the areas missed and specific contractor practices that need improvement to work specifications.

Utilities routinely need Operational Intelligence in order to determine the type of equipment that needs to be employed for various types of jobs and terrain, GIO offers online web mapping services for percent of Slope, Land Use and Topographical Maps as part of the standard GIO solution. It requires no GIS data configuration or resource dependant Geo-database loading and removes high cost of maintaining IT infrastructure and hardware.

Asset Mapping
Accurate mapping of transmission assets and GIS development is a valuable by-product of the GIO program, and industry leading software integrating LiDAR and imagery allows initial development of annual TVMP in the office reducing field costs and improving productivity. Structures and features are accurately positioned in 3 dimensions to sub-meter accuracy. Location of all substations, power plants, and structure attributes are catalogued and confirmed with separate image tables for forward oblique structure, Right of Way (ROW) and down-looking views. An attribute database is configured to customer specifications and capable of creating tables for a customer-defined list of attributes with the ability to add historical data and New Lines of Services, Vegetation/encroachment analysis and complete system benchmark

An Asset Inventory includes separate data tables for all circuits, structures, poles, substations, spans, and attachments; Lines coded by voltage; Links to inspection and maintenance databases; Population data along right-of-way; and Environmental concerns and notations.

Clearion Software Integration
Under an exclusive agreement with GeoDigital, Clearion Software has adapted their Transmission Vegetation Management (TVM) software solution to integrate and use LiDAR data and imagery generated by GeoDigital. The resulting software is an enterprise solution that enables users to create, share, track, and audit map-based vegetation and asset management information. The software supports the planning and management of routine vegetation treatments, as well as emergent issues that arise from visual inspections or LiDAR surveys.

With detailed work tracking and reporting capabilities, and full integration with LiDAR and imagery the resulting software provides the tools and data required to improve reliability and meet NERC regulatory requirements.

The software can incorporate existing asset and land base data from a corporate AM/FM/GIS as intelligent background layers within the Vegetation Management application., and allows vegetation managers to create prescriptions (work plans), issue paper or electronic work orders, track post-work inspections and rework, calculate estimated and actual costs, and manage schedules and budgets.

Two Real-World Beneficiaries of GIO Business Intelligence
Northeast Utilities (NU) saved close to $1.485 Million on their vegetation clearance budget and helped the environment with GIO business intelligence.

With $2.5 million budgeted for removal of red cedars from their ROW over a five year period, NU was able to satisfy reliability and environmental concerns to avoid clear-cutting their ROW with the use of aerial LiDAR surveys which allowed NU to manage vegetation issues proactively and selectively remove only trees that posed a threat of encroachment into the minimum clearance distances required by NERC and as a result saved $1.48 million.

GIO allowed NU to focus in on specific trees during 2009 and all problems were addressed and corrected at an annual expenditure of only $80K for the selective removal of cedar trees on the ROWs. The program for 2010 was to continue with additional removal of cedar trees in the next clearance category to ensure that all problems would have been removed to allow for a longer period of time where cedars would not be an issue and the number removed would be drastically reduced to appease their regulatory agencies.

Based on the anticipated costs of the remaining four-year cedar removal effort, the budget for this work was $2.0 million. The LiDAR surveys as well as the costs for the corrective actions employed in 2009 and the budget for 2010 is only $520K. Therefore, the net cost savings by using the LiDAR surveys and GIO business intelligence to selectively address only those trees that were a potential compliance issue is $1.48 million over the previous four-year period.

PPL Transmission became convinced of the value of GIO business intelligence and multi year audits when they discovered ordered prescriptions were either not being performed as defined or not performed at all. Sophisticated change detection processes from multi-year audits is seen by PP&L as an effective means to determine that work prescribed actually gets done as ordered.

PPL discovered the impact of Clearance Auditing. LiDAR change detection was able to show with colorization for grow-ins, fall-ins, areas of clearance and non clearance. For example, some areas that required clearance, for one reason or another, were just trimmed by the contractor, which will require further trimming in subsequent years, and the associated recurring revenues for the contractor. Correlating alleged clearance areas of grow-in risk with actual trimming and pruning is good business practice.

Conclusion:

GeoDigital is pushing the evolution of LiDAR and geospatial information to what utilities really need, which is actionable business intelligence in order to meet, or exceed, regulatory requirements, ensure reliability, protect critical infrastructure and the environment.

Aerial LiDAR surveys and GIO business intelligence have proven invaluable in documenting critical data and information that has been closely held by key individuals and is being lost to organizations at an alarming rate due to personnel attrition. It also identifies changes to the infrastructure and transforms that data into a company resource in digital format that can be used across the organization.

Geospatial business intelligence facilitates the ability to integrate various renewable generation resources, providing site and route selection, environmental impact studies and regulatory compliance to simplify interconnection processes as the grid shifts to a more decentralized model with the integration of smaller, distributed renewable energy sources.

Accurate as-built data of the entire ROW including structures, facilities, vegetation and incursions derived from the LiDAR data is valuable to transmission engineering in optimizing asset utilization and operational improvements by improving load factors and lowering system losses, provides the knowledge to build only what is needed …improve asset and resource management processes …reduce utility costs and generate more power through existing assets. The stakes have gotten so high for utilities and transmission organizations, they need more and better information…geospatial information alone is no longer enough … what they really need is actionable business intelligence.

The Advantages of IEC 61850 Process Bus Over Copper-Based Protection and Control Installations

Steven Hodder, Rich Hunt, Dave McGinn, Bogdan Kasztenny, Mark Adamiak
GE Digital Energy

1. Introduction

This paper reviews key aspects of the process of implementing traditional hard-wired solutions utilizing integrated multi-function relays and compares them with implementing the equivalent system using an IEC 61850-9-2 [1] process bus solution [2]. The various benefits as they relate to the engineering, construction, commissioning, and routine maintenance from transitioning from traditional Protection and Control (P&C) systems to a process bus solution are reviewed.

Typically benefits are translated into specific cost savings on a project. Recognizing differences in absolute cost and relative costs of materials and labour, as well as other factors such as accounting for constraints resulting from labour regulations, relative currency differences and so on, specific financial costs savings are difficult to predict in a general case. However, by deploying practical IEC 61850 process bus-based P&C systems, it is estimated that total labour savings approaching 50% or more are realizable over the life of the system, particularly in green-field installations.

Not all benefits can directly be translated into specific monetary savings. A number of benefits relate to the ability to better optimize the utilization and deployment of resources, improving the overall efficiency in using both capital and operating & maintenance budgets. This paper presents evidence as to these assertions.

2. The Traditional Protection & Control System

The traditional P&C system uses individual copper wires to transmit signals from the switchyard to protective relays in the control house. Each copper wire for an individual signal is terminated at the primary apparatus in the switchyard, pulled through cable trenches to a termination block in the control house, then is terminated numerous times within the control house through terminal blocks, test switches and various relay terminals. The signal is then returned from the relay to the primary apparatus through even more terminations. One complete copper signal path typically requires 8 or 10 terminations.

During the design phase, these numerous copper connections result in large amounts of variability in engineering design. Each design and application will be unique, based on the individual site location, designer and design requirements. Design changes require significant manual labour to implement the changes in the copper connectivity. Each change usually requires a skilled draftsperson revising a large number of drawings manually. Materials are procured and installed as individual components in the system, and the number and type of materials vary between zones, again due to all of the variability introduced by the copper wiring.

On-site construction, commissioning and maintenance also expend a great deal of effort, and consequently carry a high cost, dealing with copper wiring. Each wire and termination is made by hand in the field, one wire at a time, using expensive, skilled labour. The integrity of each copper signal path needs to be verified during commissioning, and errors require troubleshooting and rework to correct. High-energy signals from primary equipment are brought to the control house and therefore test switches are required during maintenance procedures to isolate these signals for both personnel and equipment safety. Isolating and restoration of individual signals using test switches during maintenance carry a risk of human error and misoperation of protection, as all of the correct test switches must be opened to start maintenance safely, and then correctly restored for proper system operation after restoration.

Project management is difficult, as there are large requirements for skilled labour, and many handoffs between engineering, drafting, construction, and maintenance groups in the utility. All of these handoffs must be accounted for in the project schedule, and a delay in one group handing their output to the next group can have significant impact to the project in terms of both delays and cost overruns.

3. A Practical Process Bus System

One example of a practical IEC 61850 process bus system is the HardFiber system from GE shown in Figure 1. This system is made up of a small number of standardized components, almost completely connectorized for fast installations and easy replacement. The system itself is naturally scalable, supporting the addition of new zones and modifications to existing zone in a straightforward and low-risk manner.

4. The Benefits of IEC 61850 Process Bus

Benefits of a particular process bus system, the HardFiber System [3], can be found at every step of the design, installation, and maintenance of P&C systems. Standardized components, copper terminations that end at merging units installed at primary apparatus in the switchyard, and purpose-driven, straightforward architecture simplify procurement, engineering, drafting, construction, commissioning, maintenance, and operations.

4.1 Materials

With the HardFiber system, materials become a finite set of standard components, with a small number of each type, across all zones and stations. Regardless of the physical construction or vintage of the associated primary apparatus and the nature of the project (new construction versus retrofit), the interface to the primary power system is always exactly the same. Even the order code for the associated protective relay is reduced to a relay with a single IEC 61850 Process Card for virtually every application.

Control buildings and cable trenches can be greatly reduced in size due to elimination of most of the bulky copper cables, terminal racks and AC and DC test switches on relay panels.

4.2 Engineering

The interface between the protection and control system and the power system is always presented exactly the same, regardless of the actual physicals of the substation – the interface is always a Brick located in the switchyard at the end of a fiber optic communications channel. There is only minor physical variability in mapping Bricks to specific relays, based on the topology of the switchyard as mirrored in the provisioning of specific protection & control zones. All of the variability with respect to the mapping of specific power system signals is transferred completely into the specific configuration of each relay involved in protection and control, as opposed to the mapping and connection of specific physical signals via copper wiring.

The HardFiber system is based on the well-proven Universal Relay (UR) family of protection and control relays, covering a wide range of protection applications and zones. The use of a known relay product line, coupled with the fact that the fundamental operation of the relay algorithms remains unchanged, greatly reduces the risk and amount of type testing necessary to adopt, adapt and deploy the HardFiber system.

4.3 Drafting

The only documentation required for copper connections in the switchyard is in the interface wiring between the primary apparatus and the corresponding Brick I/O. These documents can be standardized to each primary equipment vendor and type. The documentation for the installation of the Bricks in the primary apparatus may be specified as deliverable as part of purchase of apparatus.

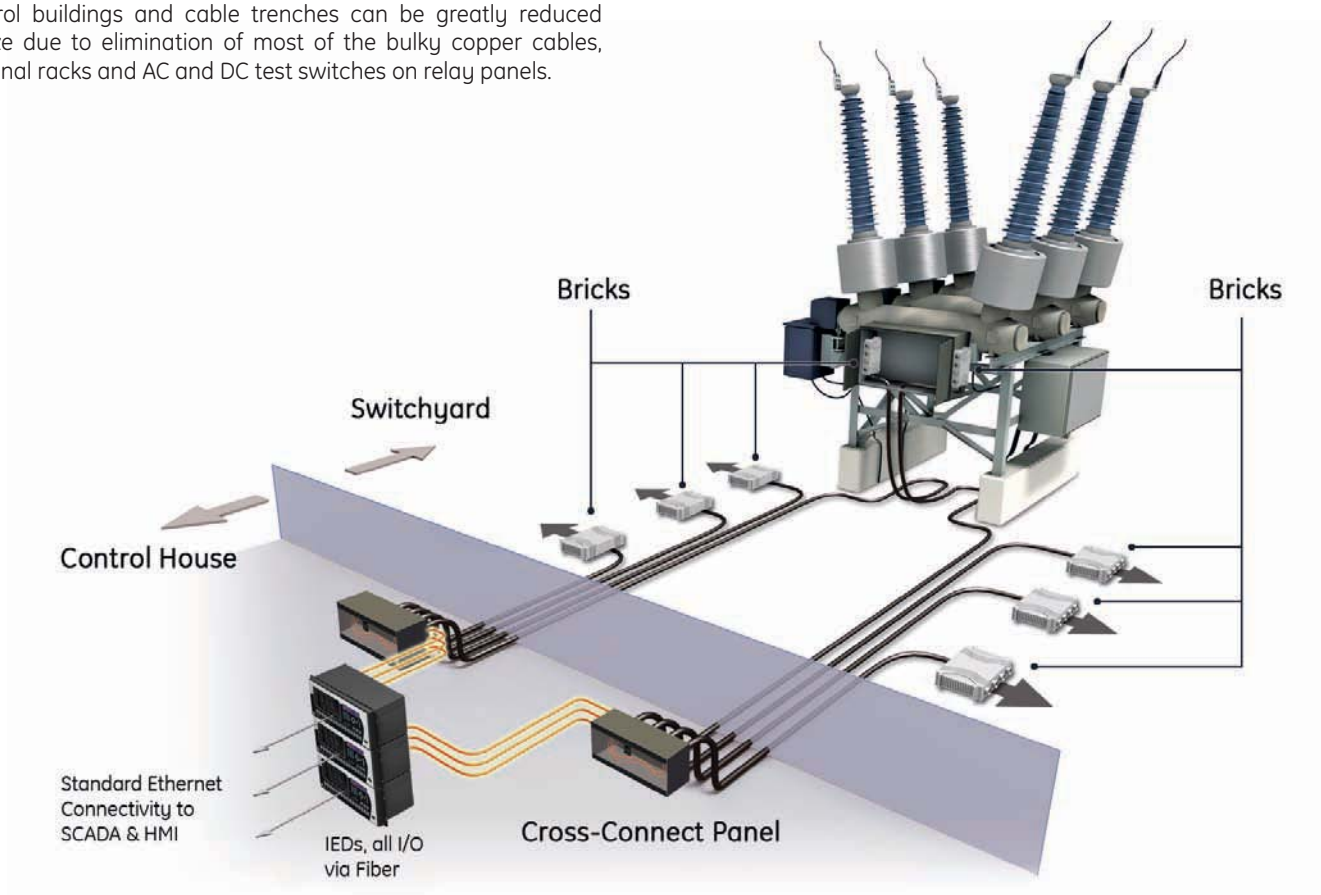

Figure 1.
HardFiber process bus architecture

Within the control house, the amount of documentation for the connectivity is vastly reduced and simplified to single point-to-point fiber connections. These connections can be summarized in tabular form as opposed to drawings, and may even be automatically generated by software to create system and connection documentation.

4.4 Construction

The construction effort needed to make on-site copper connections, and is virtually eliminated when the apparatus manufacturer installs Bricks in the primary apparatus prior to delivery to site. The chance for errors is vastly reduced by eliminating the majority of copper terminations and by standardising the physical connectivity between the primary apparatus and the Bricks.

The simplified interface point to the switchyard offered by the Cross Connect Panel provides faster on-site installation for P&C systems, particularly where turn-key control buildings are used with primary apparatus pre-wired with Bricks.

4.5 Commissioning and Maintenance

Continuous monitoring of the architecture and equipment reduces protection misoperations from incorrect isolation or restoration during protection testing [4]. Construction errors are limited to provisioning of communication between origin and destination of information. No high-energy signals (AC or DC) are present in the control building for greater personnel safety when working on protection and control systems.

By providing the opportunity to use fully duplicated field measurement hardware (Bricks), along with continuous self-monitoring of all hardware and communications allows maintenance to be condition-based (event-driven, e.g. run-to-fail) as opposed to calendar-based periodic maintenance. This reduces the costs associated with maintenance over the entire life of the P&C system, and reduces the opportunity for power system interruptions to occur due to human error during isolation and restoration of a P&C system during routine maintenance.

4.6 System Modifications & Switchyard Additions

The HardFiber system's point-to-point architecture allows for the same degree of scalability that traditional hardwired P&C systems provide. Each zone can be conveniently engineered, installed and commissioned individually without impacting adjacent zones. For retrofit applications, the HardFiber system can be deployed for a single zone only, for example the addition of a new capacitor bank on an existing station, without disturbing the existing in-service protection nor requiring the entire station protection be converted to a process bus-based solution.

Similarly, existing process bus-based protection zones may be expanded to incorporate new power system elements by tapping to the newly added Brick. The dedicated point-to-point architecture of the HardFiber system allows new zones and new equipment to be added and integrated without concerns regarding isolation for existing protection and control applications or adverse system performance from increased network traffic.

4.7 Project Management

Procurement, engineering, and construction are greatly standardized, and fewer handoffs with less labour effort required at each stage increase productivity and helps control and reduce project cycle times. Up-front decisions regarding material planning are simplified, so engineers and draftpersons can be engaged earlier on detailed design work, without needing the complete physical details of the installation.

Another advantage is the execution of work on-site is almost completely decoupled from the presence of large components like breakers and a control at the substation. Outdoor fiber optic cables for the Bricks can be run at convenient time when labour is available, even if the Bricks have not been installed yet. Turn-key control houses can be assembled in a controlled environment and completely tested to the demarcation point (Cross Connect Panel) prior to delivery to the substation site. Bricks can be installed in the primary apparatus, and even tested in-situ to ensure the correctness of the copper interface wiring. Ideally, new breakers or refurbished breakers will have the Bricks installed and tested in the controlled environment of the breaker shop. The on-site installation then becomes the simple task of making fiber optic connections between the pre-tested relays in the control house and pre-tested Bricks in the switchyard – a truly "plug-in" substation project.

4.8 Operations

The high degree continuous self-monitoring and optional duplicated measurement hardware allows the hardware implementing protection and control to detect spontaneous failures and go into a fail-safe state, thereby preventing certain protection maloperations and the corresponding unexpected outage of the primary power system. The Brick, with its connectorized cabling and no internal settings or firmware facilitate fast replacement of hardware without requiring long outages to re-commission protection and control systems in the event of a hardware failure.

4.9 Cyber Security

The dedicated, point-to-point architecture of the HardFiber system does not contain any active network switching or routing hardware, and therefore does not require any external access for monitoring or configuration purposes. Due to its completely isolated nature, the HardFiber system as designed is implicitly secure from external cyber security threats and by design complies with cyber security requirements.

5. Conclusions

In this paper, some of the advantages have been presented that are realized by deploying an IEC 61850 process bus solution like the HardFiber System to implement power system protection & control systems.

Copper-based signalling is the central question in the IEC 61850-9-2 process bus discussion. Copper wiring is a source of physical variability that not only generates the majority of the labour cost, but also prevents transition of the industry from a "workshop" mode of production to a factory mode: with less assembly done in-situ by hand and more physical elements pre-tested and shipped with a manufacturer's warranty. This optimization of labour is going to become a key consideration in the electricity sector for many years to come [5].

Utilities should strategically look at the adoption of a low-risk process bus solution like the one presented in this paper and take advantage of all of the tangible business benefits such as project cost reduction, faster facility construction, lower maintenance costs and improved reliability that this exciting new technology offers.

6. References

[1] IEC International Standard "Communication networks and systems in substations - Part 9-2: Specific Communication Service Mapping (SCSM) – Sampled values over ISO/IEC 8802-3", (IEC Reference number IEC/TR 61850-9-2:2004(E), IEC, Geneva, Switzerland).

[2] HardFiber System Instruction Manual, GE Publication GEK-113500.

[3] B.Kasztenny, D.McGinn, S.Hodder, D.Ma, J.Mazereeuw, M.Goraj, "A Practical IEC61850-9-2 Process Bus Architecture Driven by Topology of the Primary Equipment" (42 CIGRE Session, Paris, August 24-29, 2008, paper B5-105).

[4] D.McGinn, S.Hodder, B.Kasztenny, D.Ma, "Constraints and Solutions in Testing IEC 61850 Process Bus Protection and Control Systems" (42 CIGRE Session, Paris, August 24-29, 2008, paper B5-206).

[5] W.K.Reder, "The Technical Talent Challenge and Implications of Our Maturing Workforce" (IEEE Power and Energy Magazine, January/February 2006, pp.32-39).

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	)))	**Docket No. ER11-___-000**

VERIFICATION

State of Connecticut)
) ss. Berlin
County of Hartford)

I, James A. Muntz, am submitting this testimony in the above-captioned proceeding for Northern Pass Transmission LLC. My business address is Northeast Utilities Service Company, 107 Selden Street, Berlin, Connecticut, 06037. I submit this verification to verify that the Prepared Direct Testimony of James A. Muntz was prepared by me, with the assistance of others working under my direction and supervision, and that the contents are true to the best of my knowledge, information and belief. Executed in Berlin, Connecticut this __th day of December, 2010.

James A. Muntz

James A. Muntz

SUBSCRIBED AND SWORN to before me
on this 15th day of December, 2010.

Diane S. Farymiarz
Diane S. Farymiarz
Notary Public

My commission expires: 11/30/2014

Appendix C

Joint Direct Testimony and Exhibits of Michael J. Auseré and Geoffrey O. Lubbock

Exh. No. NPT-300

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	**)**	**Docket No. ER11-___-000**

PREPARED JOINT DIRECT TESTIMONY OF
MICHAEL J. AUSERÉ
OF NORTHEAST UTILITIES SERVICE COMPANY
AND
GEOFFREY O. LUBBOCK
OF
NSTAR ELECTRIC & GAS CORPORATION

December 15, 2010

EXHIBITS

Exhibit No. NPT-300	Direct Testimony of Michael J. Auseré and Geoffrey O. Lubbock
Exhibit No. NPT-301	Table showing average costs of NU and NSTAR's transmission upgrades
Exhibit No. NPT-302	Cost forecast and spending timeline of the NPT Line

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC) Docket No. ER11-___-000

PREPARED JOINT DIRECT TESTIMONY OF
MICHAEL J. AUSERÉ
OF NORTHEAST UTILITIES SERVICE COMPANY
AND
GEOFFREY O. LUBBOCK
OF NSTAR ELECTRIC & GAS CORPORATION

I. INTRODUCTION

Q. Mr. Auseré, please state your full name and business address.

A. My name is Michael J. Auseré. My business address is 56 Prospect Street, Hartford, Connecticut 06103.

Q. Mr. Auseré, by whom are you employed and in what capacity?

A. I am the Vice President – Finance of Northeast Utilities Service Company ("NUSCO"), a service company subsidiary of Northeast Utilities ("NU") that provides centralized services, such as accounting, finance, treasury, legal, purchasing, and administrative functions to NU and Northern Pass Transmission LLC ("Northern Pass"), as well as NU's other subsidiaries, including its transmission-owning subsidiaries, The Connecticut Light and Power Company ("CL&P"), Western Massachusetts Electric Company ("WMECO"), and Public Service Company of New Hampshire ("PSNH").

Q. Mr. Auseré, what are your areas of responsibility in this position?

A. I am responsible for corporate financial forecasting, planning and analysis and financial policy.

Q. Mr. Auseré, please describe your educational background and employment experience.

A. I graduated from the University of Texas at Austin with a Bachelor of Business Administration in Accounting and a Master in Professional Accounting. I came to Northeast Utilities in 2009 from Energy Future Holdings ("EFH") in Dallas, Texas where I served as Vice President of Planning and Analysis for their electricity generation and wholesale marketing and trading businesses. Prior to that position I was Vice President and Controller for EFH's retail and wholesale marketing and trading businesses. Before joining EFH in 2000, I spent eight years with PricewaterhouseCoopers in work that was heavily focused on the energy sector. My assignments included lead manager on the worldwide audit of ExxonMobil.

Q. Mr. Lubbock, please state your full name and business address.

A. My name is Geoffrey O. Lubbock. My business address is One NSTAR Way, Westwood, Massachusetts, 02090.

Q. Mr. Lubbock, by whom are you employed and in what capacity?

A. I am employed by NSTAR Electric & Gas Corporation, a service company within the NSTAR holding company system, as Vice President – Financial Strategic Planning and Policy.

Q. Mr. Lubbock, what is your education and professional background?

A. I have a Bachelor and Master of Arts from Cambridge University and a Masters Degree from the London Graduate School of Business. I joined Boston Edison Company, now named NSTAR Electric Company, in 1988 as Manager of Revenue Requirements. In 1991, I became Manager of Revenue Requirements and Financial Planning. In 1993, I became Manager of Energy Research Planning and Forecasting. In 1995, I became Manager of Corporate Service Commitments and in 1997, I became Director of Generation Divestiture. I assumed my current position in July 1998. Prior to Boston Edison, I was with the Cabot Corporation, Exxon Corporation and Citibank.

Q. What is the purpose of your testimony?

A. Our testimony provides support for Commission acceptance of a bilateral cost-based Transmission Service Agreement ("TSA") between Northern Pass and H.Q. Hydro Renewable Energy, Inc. ("HQ Hydro Renewable"), a subsidiary of Hydro-Québec, that was executed on October 4, 2010. The TSA provides for Northern Pass to construct a 1,200 MW high voltage direct current transmission line from the US/Canada border to Franklin, New Hampshire and

a radial 345 kV alternating current line from Franklin to the Deerfield substation in New Hampshire, which would collectively be called the Northern Pass Transmission Line ("NPT Line") for the provision of firm transmission service over the NPT Line. Hydro-Québec TransÉnergie ("TransÉnergie") intends to construct the 1,200 MW high voltage direct current transmission line from the US/Canada border to Québec (the "Québec Line"). The transmission service represents a great opportunity for residents of New England to benefit from the importation of low carbon power from Québec at no premium to market prices as explained in the testimony of Mr. James A. Muntz (Exhibit No. NPT-200).

The TSA contains three provisions that the Commission may view as transmission incentives under Order No. 679. Our testimony, along with the testimony of Mr. James A. Muntz (Exh. No. NPT-200) and a report provided by Charles River Associates (Exh. No. NPT-700), provides support for those incentives. In particular, we will (1) describe Northern Pass, the reasons for creating this new entity, its corporate structure, and its capital structure; and (2) illustrate the extraordinary nature of the NPT Line, and the financial risks and challenges that Northern Pass and its ultimate parent entities, NU and NSTAR, face with respect to the construction and ownership of the NPT Line, including the unique risks that Northern Pass has assumed under the TSA.

Q. What are the three TSA provisions that could be viewed as Order No. 679 incentives?

A. The three TSA provisions that could be viewed as Order No. 679 incentives are: (1) a return on equity ("ROE") of 12.56 percent during the construction period for purposes of calculating the Allowance for Funds Used During Construction ("AFUDC"), and upon commercial operation, an ROE equal to the base ROE under the ISO New England Inc. ("ISO-NE") regional rates plus an adder of the lesser of 142 basis points or an amount that would not cause the total ROE to exceed the applicable zone of reasonableness; (2) the parties' termination rights under the TSA under certain limited circumstances, which give rise to the equivalent of the abandoned plant cost recovery that the Commission has approved as an incentive; and (3) the establishment of a regulatory asset for certain costs incurred prior to commercial operation that are not included in FERC Account No. 107 as Construction Work in Progress ("CWIP").

Q. What is the basis, other than Order No. 679, for approval of those three provisions?

A. The Commission should approve these provisions as essential elements of the parties' contract without the need to refer to Order No. 679. The TSA, inclusive of these three provisions, is the product of extensive and meticulous negotiations between sophisticated parties, the end result of which is a complex

allocation of risks and exchange of considerations. A piecemeal disallowance of any of the three provisions would overturn the balance of risk sharing and considerations which the parties have achieved through almost a full year of negotiation.

II. NORTHERN PASS

Q. Please describe the structure of Northern Pass.

A. Northern Pass is a joint venture limited liability company formed by NU Transmission Ventures, Inc., ("NU Ventures"), a wholly-owned subsidiary of NU, and NSTAR Transmission Ventures ("NSTAR Ventures"), a wholly-owned subsidiary of NSTAR. NU Ventures is a 75 percent owner of Northern Pass, and NSTAR Ventures is a 25 percent owner. Northern Pass has its principal place of business in New Hampshire. Northern Pass will be the developer and owner of the NPT Line. During the construction phase, Northern Pass will be capitalized through a combination of equity contributions from NU and NSTAR and debt financing obtained by Northern Pass itself.

Q. Why have NU and NSTAR formed a new entity to construct the NPT Line?

A. This joint venture to develop, site, finance, construct, own and maintain the NPT Line provides a means for NU and NSTAR and their affiliates to bring their experience, skills and capabilities collectively and cooperatively to bear

on the $1.1 billion NPT Line transmission project with broad benefits to New England consumers.

Q. Does the joint venture structure provide any additional advantage?

A. Yes. Due to the heightened risk profile of the NPT Line, NU and NSTAR created this joint venture structure in order to protect their regulated public utilities -- CL&P, WMECO, PSNH, and NSTAR Electric Company -- and their respective customers from exposure to risks associated with the NPT Line.

III. CAPITALIZATION

Q. What will be Northern Pass's sources of capital?

A. During construction, NU and NSTAR will periodically make equity capital contributions to Northern Pass such that Northern Pass meets its obligation under the TSA to use commercially reasonable efforts to maintain a capital structure of 50 percent equity including accrued AFUDC. This will be done in accordance with Section 5.6 of the TSA, which obligates Northern Pass to enter into an equity commitment agreement with NU and NSTAR. Northern Pass plans to enter into a construction loan agreement for the balance of its construction financing needs. Specifically, the TSA provides that Northern Pass will use commercially reasonable efforts to enter into a construction loan agreement with Hydro-Québec on terms and conditions that are customary for fully secured project financings of a similar nature to the NPT Line. HQ Hydro Renewable asked for this provision because it wants to reduce Hydro-

Québec's overall costs to support the project and believes that Hydro-Québec will be able to provide lower cost financing than traditional market lenders. Negotiations between Northern Pass and Hydro-Québec are currently underway as to the terms and conditions of a construction loan agreement. Short-term financing prior to the receipt of funds under the construction loan is expected to be obtained through the NU System Money Pool.

Northern Pass is obligated to use commercially reasonable efforts to maintain a capital structure that includes 50 percent equity. This obligation continues after construction is completed and the NPT Line is in commercial operation. Prior to completion of construction, Northern Pass will solicit competitive bids from potential lenders for long-term financing to refinance the construction loan. Internally generated cash flows will also be a source of capital for Northern Pass.

Pursuant to TSA § 5.1.2(e)(ii), HQ Hydro Renewable or one or more of its affiliates has the right to submit a competitive bid for post-construction term financing. However, the obligations to secure financing for the construction period and long-term financing for the in-service period remain with Northern Pass. Thus, with respect to debt financing for the project post-construction, it will be important for Northern Pass to have an investment grade rating so that it will be able to obtain capital on commercially reasonable terms.

Q. What credit ratings are you targeting for Northern Pass?

A. Upon completion of construction of the NPT Line, to ensure that Northern Pass will have access to long-term financing on commercially reasonable terms, Northern Pass is targeting investment grade ratings to meet the expectation of capital providers. In addition to increasing Northern Pass's access to capital markets, such ratings would result in lower borrowing costs.

Q. Please describe the importance of Northern Pass's 50 percent debt and 50 percent equity target capital structure under the TSA.

A. Northern Pass's capital structure under the TSA should provide for strong credit metrics that will assist the company in meeting its credit ratings target discussed above. Furthermore, this capital structure and the proposed ROE will provide Northern Pass an operating margin to withstand the business risk of unforeseen events. The proposed capital structure is also prevalent in the electric utility industry. For purposes of calculating transmission charges, Northern Pass will use a capital structure exactly equal to 50 percent debt and 50 percent equity, which is consistent with Northern Pass's contractual obligation to maintain this same capital structure to the extent commercially practicable.

Q. Does an investment grade rating increase the potential pool of Northern Pass investors?

A. Yes. An investment grade rating provides the borrower with access to a larger segment of both public and private capital markets, in part because certain large institutional investors are precluded by law from investing in non-investment grade rated instruments. Additionally, most institutional investors limit their exposure to lower rated securities. The larger base of investors (and lenders), all competing to make the investment, will increase Northern Pass's ability to obtain borrowed funds on favorable terms and conditions.

IV. MAGNITUDE OF THE NPT LINE

Q. Please discuss the magnitude of the NPT Line.

A. The NPT Line is a large-scale transmission project. At an estimated cost of $1.1 billion, including AFUDC, the NPT Line will be one of the largest transmission projects in New England.

Q. Mr. Auseré and Mr. Lubbock, how does the required investment by your companies in the NPT Line compare with their normal, routine transmission upgrades?

A. The $1.1 billion NPT Line is of a size and complexity that represents significantly more risks and challenges than the less costly, routine reliability-based transmission upgrades that our operating companies ordinarily undertake. The large capital expenditure requirements for each of our

companies in connection with the NPT Line, by any cost comparison metric, represent a significant financial investment for our companies. NU, through its majority interest of Northern Pass, will own 75 percent of the NPT Line and its share of the investment in the project, either directly or through its subsidiaries, will be over three quarters of a billion dollars. As a 25 percent owner, NSTAR's equivalent investment will be over one-quarter billion dollars.

Aside from large-scale projects like NU's Middletown-to-Norwalk and NEEWS Projects and NSTAR's 345 kV Underground Project, the two companies' $1.1 billion capital commitment to the NPT Line dwarfs their average transmission project. As shown in our Exhibit No. NPT-301, NU's transmission upgrades for the period 2006 to 2009 had an average cost of approximately $4 million, and NSTAR's transmission upgrades for the period 2006 to 2009 had an average cost of approximately $5.3 million. *See* Exh. No. NPT-301.

Q. Mr. Auseré and Mr. Lubbock, is the NPT Line the kind of project that NU and NSTAR would typically undertake in the ordinary course of their business?

A. No. NU and NSTAR have entered into this international project for the specific purpose of providing access to a substantial amount of renewable, low carbon energy in Canada. To achieve that objective, they have committed to a project with the construction, technical, operating and related challenges

described by Mr. Muntz and the financial and other challenges described above and hereafter in our testimony. Further, we segregated the development costs associated with the NPT Line from our routine transmission planning costs and funded the initial development of the NPT Line with shareholder funds with no path to cost recovery from traditional utility customers. The NPT Line is clearly not a routine, ordinary-course-of-business reliability-based transmission upgrade.

In addition, the NPT Line presents a unique risk for our companies because the fifty percent equity in this $1.1 billion project will not be compensated in the normal manner for utility assets with the payments obtained from customers under the ISO-NE Open Access Transmission Tariff ("OATT") or retail tariffs. Northern Pass (and its ultimate parent entities, NU and NSTAR) are relying on funds from a single customer to pay back their investment over a forty-year term. This represents a unique risk that distinguishes this project from other projects, even those of comparable size that have obtained incentive treatments from the Commission in the past.

V. RISKS OF NPT LINE PROJECT

Q. Does Northern Pass have unique financial risks in connection with the NPT Line project?

A. Yes. In negotiating the TSA, NU and NSTAR used as a starting point the general risk allocation our companies would assume in connection with a

regulated transmission project developed and built under the ISO-NE regional system planning process as reflected in the OATT. Even though this was a negotiating benchmark, it was not the end result of the negotiations. While the ROE of 12.56 percent is consistent with the ROEs granted to NU and NSTAR's large-scale transmission projects referenced above (i.e., 12.89 percent for NEEWS, 12.64 percent for the Middletown-to-Norwalk project (including 13.1 percent for the underground portion of the Middletown-to-Norwalk project that employs advanced transmission technologies), and 12.64 percent for NSTAR's 345 kV Underground Project), the project exposes Northern Pass, and NU and NSTAR as Northern Pass's equity owners, to a significantly higher level of financial risk relative to that traditional regulatory benchmark. This testimony and Mr. Muntz's testimony provide a number of examples that illustrate some of the unique financial risks associated with the NPT Line project developed under the TSA relative to typical transmission projects developed under the ISO-NE OATT.

Q. Can you provide an example of where this project differs from NU and NSTAR's other large scale projects developed and built under the ISO-NE regional planning process?

A. Yes. While NU and NSTAR received a cash flow return from the carrying charge on CWIP for NEEWS and the 345 kV Underground Projects, and the Commission has typically granted a cash flow recovery of CWIP as a rate base

component rather than the non-cash Allowance for Funds Used During Construction (AFUDC) as an incentive for large, non-routine transmission projects, the TSA does not provide for any cash flow return from the carrying charge on CWIP during the multi-year siting and construction period for the NPT Line. The large capital expenditures required during the construction phase will result in significant negative cash flows during this period. *See* Exhibit No. NPT-302 (cost forecast and spending timeline for the NPT Line showing the large capital expenditures during the construction phase). In addition, another unique characteristic of the NPT Line is the time period to complete the project will depend to some extent on the time required for TransÉnergie to site and construct the Québec portion of the project, and the TSA requires Northern Pass to defer cost recovery for up to an additional two years after the NPT Line is completed if the Québec portion of the project is not completed on time. Deferral of these cash flows represent heightened risk for the project.

Q. Does any risk result from the fact that the only counter-party to the TSA is HQ Hydro Renewable?

A. Yes. The TSA is a "single-payer" or "single-customer" contract. Specifically, HQ Hydro Renewable is the sole customer that commits to take long-term firm transmission service over the NPT Line. Therefore, the success of the contract is dependent on the credit and cooperation of just one customer. If that

customer and its guarantor (or their successors if the TSA is assigned) were to fail financially, Northern Pass would be left without a single long-term committed customer for the full value of the NPT Line. Moreover, as we discuss later in this testimony in more detail, this single customer has multiple rights to terminate the TSA at any time, including commercial reasons and for convenience. Any such termination would also leave NPT with no committed customers for the line. This exclusive dependence on one customer is unlike a typical utility transmission project subject to the New England regional planning process, where NU and NSTAR would recover their costs from a large class of customers (essentially all New England load) receiving regional transmission service under the ISO-NE OATT. With respect to typical regional utility transmission projects, the transmission owner does not bear any additional financial risk by virtue of the credit quality of the buyer, because the buyer consists of the entirety of New England's load.

Q. Is there any unique risk associated with the fact that the TSA counter-party is an affiliate of a foreign entity?

A. Yes. HQ Hydro Renewable is affiliated with a Québec crown corporation, which in turn, is governed by Canadian laws. Despite the present cooperation between Québec and New England utilities, the fact remains that an international transaction has inherent risks that are absent in a purely domestic transaction. Although the TSA and parent guaranty include protections for

Northern Pass in the event of a default by the customer, our lawyers have advised us that it is not possible to entirely eliminate the risk associated with contracting with a sovereign entity. Of course, no comparable risk exposure exists when constructing regional transmission projects, as the costs are borne by New England load under the ISO-NE OATT.

Q. What are Northern Pass's financial risks if it is not able to obtain the necessary regulatory approvals to construct the NPT Line?

A. The TSA automatically terminates if regulatory approvals necessary to construct the NPT Line are not obtained within three years of the TSA's effective date, unless otherwise mutually extended by the parties. The risk of automatic termination is unique to this project as a typical utility transmission project under the ISO-NE Regional System Plan is not subject to an automatic termination provision if regulatory approvals are not obtained within a negotiated three year period.

Q. Does Northern Pass incur financial risks for delays in the commercial operation date of the NPT Line?

A. If the conditions precedent to commercial operation of the NPT Line have not been met by the time Northern Pass certifies in good faith that the NPT Line is ready for start-up and testing activities, HQ Hydro Renewable's obligations to make transmission service payments will be delayed until the conditions precedent are satisfied. This scenario could arise, for example, if the Québec

Line is completed later than the NPT Line. If the conditions precedent have not been satisfied by the second anniversary of the later of the target in-service date of the NPT Line and the date when the NPT Line was certified as ready for start-up and testing activities, then commercial operations will be deemed to commence on that second anniversary. TSA § 4.3.2. In that scenario, Northern Pass's receipt of revenues to repay its investment and operating costs would be delayed for up to an additional two years. The delay in receipt of revenues would likely be exacerbated if there are delays in completion of the Québec Line. It is contemplated that the construction of the Québec Line and the NPT Line would proceed concurrently, so, if there are permitting or construction delays in the Québec Line, it is likely that construction of the NPT Line would be intentionally slowed down by the parties. If that occurs, the trigger for the two year period referenced above would also be delayed, resulting in an even longer period before Northern Pass receives any revenues under the TSA. Dependence on the completion of an adjacent project in a foreign country is another feature that distinguishes the NPT Line from a typical utility transmission project.

Q. Does Northern Pass have any unique risks related to *force majeure*?

A. Yes. Section 16.4 of the TSA applies if a *force majeure* event results in a 100 percent outage for more than 365 consecutive days. In that event, the ROE

portion of the transmission service payments and depreciation expenses are suspended until firm transmission service is restored.

Q. You mentioned that HQ Hydro Renewable has termination rights under the TSA. What are these termination rights?

A. HQ Hydro Renewable has numerous termination rights under Article 3 of the TSA, including termination rights during the development phase, the construction phase and the commercial operations phase. The majority of the termination rights are either for the convenience of HQ Hydro Renewable or result from events outside the control of Northern Pass. In contrast, a transmission project under the ISO-NE regional system plan would be cancelled or abandoned only if ISO-NE removes it from the regional system plan or an essential siting approval was denied. The risk of customer termination in this case is much higher than would exist for a regulated transmission project constructed in accordance with the ISO-NE regional transmission plan.

Q. **If HQ Hydro Renewable exercises one of these termination rights, is Northern Pass entitled to full reimbursement under the TSA?**

A. Although the TSA provides that Northern Pass is entitled to reimbursements upon the early termination of the TSA by HQ Hydro Renewable, HQ Hydro Renewable is not required to pay the net present value of the equity return Northern Pass would have received during the remaining balance of the term

(i.e., lost opportunity costs) except where HQ Hydro Renewable terminates the TSA during the commercial operation phase for convenience. TSA § 3.3.10. HQ Hydro Renewable is not required to pay these lost opportunity costs if it terminates the TSA early for any of the other reasons permitted by the TSA. As a result, if there is a termination for any reason other than convenience of the customer during operations, there would be a lost opportunity cost associated with the capital that was deployed in order to design and construct the NPT Line that will not earn any return from the terminated project from and after the termination date. Upon any such termination, NU and NSTAR, as Northern Pass's owners, will have to identify potential opportunities to redeploy that capital into other projects on a going forward basis. There is a real risk that NU and NSTAR will be unable to obtain an equivalent rate of return from an acceptable alternative investment at all or within a reasonable period of time after termination. This creates potentially significant lost opportunity costs for NU and NSTAR.

Q. Does the parent guaranty provided by Hydro-Québec fully protect Northern Pass for reimbursements that are recoverable under the TSA?

A. No. HQ Hydro Renewable is a special purpose, start-up entity that currently has no assets and is unlikely ever to have assets that are commensurate in value with its obligation under the TSA. Thus Northern Pass would look to Hydro-Québec's guaranty for any termination payment obligation. This guaranty is,

however, subject to a cap, which does not cover all potential reimbursements provided for under the TSA. In particular, it does not cover lost opportunity costs.

Q. Does Northern Pass face any special risks as a result of the TSA requirement that Hydro-Québec reissue the Guaranty with a revised cap periodically during the term of the TSA?

A. The TSA provides for the guaranty to be reissued periodically with a revised cap. Hydro-Québec is a crown corporation incorporated under the Hydro-Québec Act, and we are informed that, as a result of Section 17 of the Hydro-Québec Act, it may be difficult to enforce the obligation to reissue the guaranty. Although the parties agree in the TSA that failure to deliver the revised guaranties will constitute a termination for convenience by HQ Hydro Renewable, this structure creates significant risk for Northern Pass, particularly during the construction phase when the guaranty cap will be increasing, and is a very unusual arrangement that results solely from the special status of Hydro-Québec under the Hydro-Québec Act.

Q. Is there risk associated with the decommissioning cost recovery?

A. Yes. The TSA defers the decommissioning cost recovery until the last five years of the term, unless the TSA is terminated early. Investors will view that deferred recovery as much riskier than a recovery that would occur over the life of a unit. Moreover, Hydro-Québec's parent guaranty only covers

estimated decommissioning costs, thus exposing Northern Pass to the difference between actual and estimated decommissioning costs in the event of an early termination of the TSA.

Q. What concluding comment do you have regarding the TSA-related risks?

A. The provisions of the TSA described above demonstrate that the NPT Line is not an ordinary routine transmission project and that its risks exceed those of a routine OATT project.

VI. SUPPORT FOR INCENTIVE PROVISIONS UNDER TSA

Q. Why were the three incentives selected for the NPT Line?

A. As we testified earlier, NU and NSTAR negotiated these provisions with HQ Hydro Renewable, and they go to the essence of the parties' exchange of considerations that made the TSA possible. For their part, NU and NSTAR considered the financial criteria necessary to compensate for the attendant risks of the development of the NPT Line. They concluded that these financial provisions in the TSA would make it likely that the project could be successfully developed, *i.e.*, that NU and NSTAR could each reasonably commit equity capital on competitive terms and that Northern Pass could attract necessary debt capital on reasonable commercial terms.

A. Support for the ROE Provision

Q. What support do NU and NSTAR offer for the ROE provision?

A. Our testimony has demonstrated the extraordinary, non-routine nature of the NPT Line and the risks and challenges associated with this project. Dr. William Avera provides quantitative analysis based on a variety of methodologies, including discounted cash flow analysis, that consistently demonstrate that the TSA provisions result in an ROE that is well within the zone of reasonableness as measured by stock market conditions and alternative returns available in the market for other investments taking account of differences in risk. *See* Exhibit No. NPT-600. Finally, the ROE provision in the TSA is consistent with the ROEs that the Commission has granted to several large-scale transmission projects in New England, including other NU and NSTAR transmission projects.

Q. Would you characterize the ROE Provision as reasonable?

A. Yes. In a number of orders, the Commission has found that an incentive ROE is appropriate for large-scale transmission projects with unusual risks, such as the NPT Line. In evaluating whether a project is routine, the Commission has stated that it will consider factors such as the scope of the project, the effect of the project, and the challenges or risks faced by the project. These considerations are discussed extensively in our testimony and in the testimony of Mr. Muntz. In addition, as we have previously testified, the NPT Line is

dedicated to the import of low carbon, primarily renewable energy from Québec into New England and thus displacing energy from fossil-fueled sources. Discontinuing reliance on fossil-fueled energy to the extent reasonably possible is consistent with national policy objectives.

B. Support for the TSA Termination Provisions

Q. What is the benefit of recovery of costs in the event of termination under the TSA?

A. As discussed above, the parties have agreed to various scenarios under which the TSA may be terminated and the parties' associated cost responsibilities upon such termination. These provisions are appropriate for a large scale and complex project like the NPT Line. The main benefit of the termination provisions is that they allow Northern Pass to move forward with development at this time. The assurance that at least some level of project costs will be recoverable in most instances so long as Northern Pass satisfies its contractual obligations in a prudent manner allows Northern Pass to begin ordering equipment, reserving labor and acquiring rights of way. This will allow Northern Pass to be ready to begin the construction process and facilitate Northern Pass's ability to finish the NPT Line in the projected timeframe. While Northern Pass does not anticipate that the TSA will be terminated, the NPT Line faces significant inherent construction, environmental, and regulatory risks, as described in Mr. Muntz's testimony. Therefore, there are

scenarios as set forth under the TSA that could result in the termination/abandonment of the NPT Line.

C. Support for Regulatory Asset

Q. Please describe the need for the regulatory asset.

A. As discussed in Mr. Griffin's testimony, Northern Pass is seeking authority to establish a regulatory asset to recover those costs that are incurred by Northern Pass in connection with the NPT Line that are not included in FERC Account 107 (CWIP) (excluding costs to negotiate and draft the TSA) along with carrying charges on the regulatory asset. The proposed regulatory asset is reasonable and necessary in order to allow Northern Pass an opportunity to recover NPT Line expenses incurred prior to the commercial operation date (except those associated with the contract negotiation itself). Specifically, it allows us to recover certain costs incurred prior to the effective date of the TSA filing of which this testimony is a part. Thus, in our view the regulatory asset is justified on three grounds: (1) as an essential element of the contract between Northern Pass and HQ Hydro Renewable; (2) as an Order No. 679 incentive; and (3) on conventional cost of service grounds.

Q. Are the agreed upon provisions consistent and compatible?

A. Yes, the rate provisions are consistent and compatible because they all serve to reduce financial risks and obstacles so that the NPT Line may be completed. All of these financial provisions are designed to provide certainty with respect

to the development and construction of the NPT Line, making it easier to develop and finance the NPT Line.

Q. Do you have any final comments?

A. This line is an extraordinary opportunity for the Northeast to limit its carbon emissions, and we ask the FERC to look on it favorably. As we testified earlier, the NPT Line is not the kind of transmission upgrade that our companies undertake in the normal course of their business. NU and NSTAR have created a single purpose entity to construct a $1.1 billion high voltage direct current line and an interconnected alternating current line as part of an international project involving several political jurisdictions and reliance on payment from one customer. Moreover, the driving purpose of this effort is to make low carbon renewable energy available to New England's electricity consumers. By any standard, the NPT Line is an extraordinary project and is deserving of the incentive provisions agreed to by Northern Pass and HQ Hydro Renewable.

Q. Does that conclude your testimony?

A. Yes.

Exhibit No. NPT-301

Table Regarding Average Cost of NU and NSTAR's Transmission Projects

EXHIBIT NO. NPT-301: 2006-2009 AVERAGE HISTORICAL COST OF POOLED TRANSMISSION FACILITIES

Company	Capital Additions	No. of Projects	Average Cost Per Project
NSTAR	$358,284,292	67	**$5,347,527**
NU	$1,874,449,369	469	**$3,996,694**

Source: NU and NSTAR internal accounting information

Exhibit No. NPT-302

Cost Forecast and Spending Timeline for NPT Line

EXHIBIT NO. NPT-302: NPT FORECASTED CAPITAL EXPENDITURES (MILLIONS)

2010	2011	2012	2013	2014	2015	Total
$13	$43	$111	$263	$463	$214	$1,107

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Northern Pass Transmission LLC	)	**Docket No. ER11-___-000**
	)	

VERIFICATION

State of Connecticut)
) ss.
County of Hartford)

I, Michael J. Auseré, am submitting this testimony in the above-captioned proceeding for Northern Pass Transmission LLC. My business address is 56 Prospect Street, Hartford, Connecticut 06103. I submit this verification to verify that the Prepared Joint Direct Testimony of Michael J. Auseré and Geoffrey O. Lubbock was prepared by me, with the assistance of others working under my direction and supervision, and that the contents with respect to Northern Pass Transmission LLC and Northeast Utilities Service Company and its affiliates are true to the best of my knowledge, information and belief. Executed in Hartford, Connecticut this 15th day of December, 2010.

Michael J. Auseré

SUBSCRIBED AND SWORN to before me
on this 15 day of December, 2010.

Cynthia L Rivir

Notary Public

My commission expires: 6/2011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Northern Pass Transmission LLC	)	**Docket No. ER11-___-000**
	)	

VERIFICATION

State of Massachusetts)
) ss.
County of Norfolk)

I, Geoffrey O. Lubbock, am submitting this testimony in the above-captioned proceeding for Northern Pass Transmission LLC. My business address is One NSTAR Way, Westwood, Massachusetts, 02090. I submit this verification to verify that the Prepared Joint Direct Testimony of Michael J. Auseré and Geoffrey O. Lubbock was prepared by me, with the assistance of others working under my direction and supervision, and that the contents with respect to Northern Pass Transmission LLC and NSTAR Electric & Gas Corporation and its affiliates are true to the best of my knowledge, information and belief. Executed in Westwood, Massachusetts this 15th day of December, 2010.

Geoffrey O. Lubbock

Geoffrey O. Lubbock

SUBSCRIBED AND SWORN to before me
on this 15th day of December, 2010.

Dana M. Fennelly

Notary Public

DANA M. FENNELLY
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
December 30, 2016

My commission expires: December 30, 2016

Appendix D

Direct Testimony and Exhibits of Paula M. Taupier

Exh. NPT-400

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC) Docket No. ER11-___-000

PREPARED DIRECT TESTIMONY OF
PAULA M. TAUPIER

December 15, 2010

EXHIBITS

Exhibit No. NPT-400	Direct Testimony of Paula M. Taupier
Exhibit No. NPT-401	Revenue impact statements for the first year of commercial operation
Exhibit No. NPT-402	Statement BL

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Northern Pass Transmission LLC	)	Docket No. ER11-_____
	)	

PREPARED DIRECT TESTIMONY
OF PAULA M. TAUPIER
ON BEHALF OF NORTHERN PASS TRANSMISSION LLC

I. INTRODUCTION AND EXPERIENCE

Q. Please state your name and business address.

A. My name is Paula M. Taupier. My business address is 107 Selden Street, Berlin, Connecticut 06037. I am the Director of Transmission Rates for the Northeast Utilities Service Company ("NUSCO"), which provides centralized services to the Northeast Utilities ("NU") operating subsidiaries, including The Connecticut Light and Power Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company.

Q. Please describe your educational background and employment experience.

A. I graduated from Western New England College with a Bachelor of Science degree in Electrical Engineering. Upon graduation, I was employed by the

New England Power Pool in Holyoke, Massachusetts. Then, I joined the Massachusetts Electric Company, a subsidiary of New England Electric System, currently known as National Grid, as a field engineer. Subsequently, I joined a subsidiary of NU, The Connecticut Light and Power Company, as an electrical engineer. I then held various engineering positions within the following departments at NUSCO: Substation Engineering Department and Transmission Line Engineering Department. Then, I accepted an account manager position in NUSCO's regulated Wholesale Marketing Department. I was then promoted to be the manager of Transmission Regulatory Policy & Planning. As of October 2007, I assumed my current position, as Director of Transmission Rates.

Q. What are your areas of responsibility as director of transmission rates?

A. I am responsible for the coordination and implementation of transmission revenue requirement calculations for NU's operating subsidiaries. In addition, I have the overall responsibility for regulatory interfaces for all transmission rate-related filings before the three state agencies and utility commissions and the Federal Energy Regulatory Commission. As part of these responsibilities, I have directed the preparation and filing of various documents and exhibits related to transmission rates, transmission project information and electric industry. I have submitted testimony or testified

before this Commission, the Massachusetts Department of Public Utilities, and the Connecticut Department of Public Utility Control.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the proposed formula rate included in the Transmission Service Agreement ("TSA") between Northern Pass Transmission LLC ("Northern Pass") and H.Q. Hydro Renewable Energy, Inc. ("HQ Hydro Renewable"). I am also sponsoring an annual revenue statement for the first full calendar year of commercial operation of the Northern Pass Transmission Line ("NPT Line") described in the TSA beginning on January 1, 2016.

II. FORMULA RATE UNDER TSA

Q. Please explain the proposed formula rate included in the TSA.

A. The formula rate design under the TSA is a forward looking formula. It is designed to recover the annual revenue requirement associated with the NPT Line and AC Upgrades (I discuss the AC Upgrade Costs later in my testimony). The formula rate recovers a return on Northern Pass's investment in the NPT Line plus associated income taxes, depreciation expense, operation and maintenance expenses, and other expenses associated with the NPT Line (including the AC Upgrade Costs). The formula provides for Northern Pass to forecast the revenue requirement for each calendar year and charge the resulting rates in that calendar year. TSA

§ 14.1(d). A true-up between the forecasted and actual revenue requirement would be calculated the following year, and an invoice or refund, as appropriate would be rendered based on the true-up. TSA § 14.2(c). The true-up will include interest, calculated in accordance with Section 35.19a(a) of the Commission's regulations. TSA § 14.5.

Northern Pass proposes using the average of the beginning and end of year plant balances in determining its annual revenue requirement. Northern Pass will forecast the average of the beginning and end of year transmission plant balances for the following year by estimating what plant is expected to be retired and what new plant is placed in service during that year. Northern Pass also proposes to use the average of the beginning and end of year balances for accumulated deferred income taxes, plant held for future use, plant materials and supplies, prepayments and all other rate base items. Should these estimates be incorrect, the true-up mechanism will subsequently adjust Northern Pass's rates.

Q. Please explain why the proposed formula is just and reasonable.

A. The use of a formula rate based on estimated data, including a true-up to actual with interest ensures that the customer's rates are cost-based, which is the traditional standard that the Commission has used to determine whether a rate is just and reasonable. This method has been approved by the Commission for numerous other transmission owners. The overall

structure of the proposed formula rate is very similar to that accepted by the Commission for other utilities.

Q. What is the proposed effective date for the TSA?

A. Northern Pass is requesting that the TSA become effective upon the 61st day after the FERC filing. However, HQ Hydro Renewable will not be charged under the formula rate in the TSA until the NPT Line enters or is deemed to enter commercial operation.

Q. How does Northern Pass recover the costs it incurs before HQ Hydro Renewable is billed under the formula rate?

A. The cost of constructing the NPT Line will be capitalized in accordance with the Commission's Uniform System of Accounts and recovered, beginning with commercial operation or deemed commercial operation of the NPT Line, over the term of the TSA. Costs that Northern Pass has incurred and will incur prior to commercial operation that are not capitalized in FERC Account No. 107 will be deferred and included in a regulatory asset together with carrying charges on the regulatory asset at NPT's weighted cost of capital (as calculated under the formula rate), and then amortized over the first three years of commercial operation of the NPT Line, as further described in the testimony of Timothy J. Griffin. *See* TSA § 8.1.2(e) and § 8.1.2(f).

Q. Over what period will the capital costs of the project be recovered?

A. The TSA specifies that, for purposes of calculating payments under the formula rate, the depreciable life of any depreciable asset comprising part of the NPT Line as of the commercial operation date will be forty (40) years. TSA § 8.2. This ensures that the cost of the NPT Line will be fully recovered by Northern Pass from HQ Hydro Renewable over the term of the TSA. This depreciation period is also appropriate, as it is speculative at this point to assume whether the NPT Line will be used and useful in providing utility service beyond the term of the TSA. *See* TSA Article 9.

Q. Please describe the depreciation of capital additions and recovery of decommissioning costs.

A. For purposes of calculating payments under the formula rate, the depreciable life of a capital addition that is placed in service after the commercial operation date will be the lesser of (i) its economic life and (ii) the remaining term of the Agreement as of the placed-in-service date. TSA § 8.2. As discussed further in the testimony of Timothy Griffin (Exhibit No. NPT-500), unless NPT establishes another mechanism for rate recovery that is accepted by the Commission, estimated decommissioning costs will be recovered through the formula rate over the last five years of the TSA, with a true-up to actual costs upon completion of decommissioning (absent a Subsequent Use of the NPT Line). TSA § 9.3.

The recovery of decommissioning costs upon early termination of the TSA is covered by Article 9 of the TSA.

Q. Please describe the cost recovery of AC upgrades.

A. As discussed in Mr. Muntz's testimony (Exh No. NPT-200), in connection with the construction of the NPT Line, we expect that it will be necessary to build certain upgrades or reinforcements to the New England transmission system that are required by ISO New England Inc. ("ISO-NE") under its Section I.3.9 review under the ISO-NE Transmission, Markets and Services Tariff and such additional upgrades or reinforcements as may be requested by HQ Hydro Renewable (together, "AC Upgrades"). The AC Upgrades will be constructed, owned and maintained by certain transmission owners (other than Northern Pass but which may include subsidiaries of NU or NSTAR) that own the existing facilities that are required to be upgraded. Northern Pass will enter into facilities agreements with each transmission owner to pay the costs to design, license, construct and operate the AC Upgrades.

As noted above, charges incurred by Northern Pass under the facilities agreements relating to the AC Upgrade Costs will be recovered as expenses under the formula rate. TSA § 8.5(c). In other words, through the formula rate, HQ Hydro Renewable will be responsible for the AC Upgrade Costs. Customers under the ISO-NE OATT will not be

responsible for the costs of transmission facilities that need to be constructed in order to interconnect the NPT Line to the New England power grid, unless ISO-NE determines that all or any portion of such costs are eligible for inclusion in regional rates, and HQ Hydro Renewable chooses not to fund those upgrades. *See* TSA § 8.5(e). Any costs for the AC Upgrades that Northern Pass incurs prior to the commercial operation date of the NPT Line that are not capitalized in FERC Account No. 107 will be deferred and included as part of the regulatory asset for pre-commercial operation date expenses that I discussed earlier in my testimony. Such costs will be amortized over the first three years of the commercial operation of the NPT Line, as further described in the testimony of Timothy Griffin. TSA § 8.1.2(e) and (f).

Q. What return on equity will be used in the formula rate?

A. The formula rate uses a 12.56 percent return on equity for that component of the capital structure for purposes of accruing AFUDC during the construction period of the TSA. TSA § 8.4(a). Support for this ROE is provided in Mr. Muntz's testimony and the testimonies of Messrs. Michael Auseré and Geoffrey Lubbock (Exh. No. NPT-300) and Dr. William Avera (Exh No. NPT-600). Upon commercial operation, the ROE will be adjusted, if necessary, to equal the base ROE under the ISO-NE Open Access Transmission Tariff for regional transmission service (excluding

incentives or other adders approved by the Commission) plus an adder equal to the lesser of (a) 142 basis points and (b) an amount that would not cause the total ROE to exceed the then-applicable zone of reasonableness for Regional Network Service. TSA § 8.4(b).

Q, What capital structure will be used in the formula rate?

A. Under the TSA, Northern Pass has a contractual obligation to use commercially reasonable efforts to maintain a capital structure of 50 percent debt and 50 percent equity from and after the development phase. TSA § 8.3(a). However, at all times during the term of the TSA, for purposes of calculating the transmission service payments under the formula rate, the capital structure of 50 percent debt and 50 percent equity will remain fixed. TSA § 8.3(b). As Messrs. Auseré and Lubbock describe in their joint testimony, Exhibit No. NPT-300, this is Northern Pass's target capital structure. This capital structure is consistent with capital structures used by similar single asset entities.

Q. Will HQ Hydro Renewable have an opportunity to review the charges calculated under the formula?

A. Yes. Under the TSA, HQ Hydro Renewable will have input with respect to rates. First, HQ Hydro Renewable will be represented on Northern Pass's management committee. That management committee will, among other things, review and may approve construction budgets for the NPT Line.

For instance, the TSA provides that within 45 days after the TSA is executed, Northern Pass will provide the management committee with a preliminary budget and schedule, as well as a cost-of-service estimate for the first full year of service. At HQ Hydro Renewable's request, Northern Pass will provide the management committee with copies of the data, invoices, price sheets and other information used in the preparation of the proposed preliminary budget and schedule. The management committee may approve the preliminary budget and schedule in whole or in part. TSA § 5.2.1.

During the construction phase, Northern Pass will be required to update the construction budget and schedule on a quarterly basis. And, at HQ Hydro Renewable's request, Northern Pass will provide the management committee with copies of the data, invoices, price sheets and other information used in the preparation of the construction budget and schedule. The management committee will review and may approve the construction budget and schedule in whole or in part. TSA § 5.2.2. HQ Hydro Renewable is entitled to terminate the TSA if there is a material cost increase in the construction budget – i.e., if a budget increase of more than 15 percent over the immediately preceding budget or 30 percent over the preliminary budget, subject to an obligation to make certain termination payments. TSA § 3.3.6. Additionally, Northern Pass is required to prepare

and submit to the management committee a progress report on a monthly basis as to the costs that were actually incurred in the prior month, the associated activities and the current status of the NPT Line. TSA § 5.2.4.

Under the TSA, HQ Hydro Renewable will have audit rights for all amounts included in the formula rate. Specifically, if HQ Hydro Renewable believes that Northern Pass has miscalculated or incorrectly included charges under the formula rate, HQ Hydro Renewable has the right to submit the matter to the management committee for resolution. And if an impasse occurs, HQ Hydro Renewable will have the right to file a complaint with FERC seeking an order requiring Northern Pass to comply with the formula rate as filed. TSA § 8.1.5, § 14.2 and § 14.3.

Q. In your opinion does the formula rate proposed by Northern Pass in this proceeding conform to Commission precedent with respect to formula rates?

A. Yes. The classification, functionalization and allocation factors used for the cost items reflect standard Commission ratemaking. The estimate and true-up functions also reflect Commission precedent. Furthermore, all data used in the formula will be taken directly out of Northern Pass's FERC Form 1 or its books and records.

Q. Are you sponsoring a revenue statement for the proposed formula rate?

A. Yes, I am sponsoring an annual revenue statement for the first full calendar year of commercial operation, beginning on January 1, 2016. This revenue statement is illustrative in nature and is based upon the assumption that the NPT Line will enter commercial service prior to January 1, 2016. *See* Exhibit No. NPT-401. This exhibit also includes the projected monthly charges for the first twelve months of service under the TSA. The projected monthly charges are based on the annual revenue statement, and like that statement are illustrative in nature**.**

Q. Are you sponsoring any Cost of Service Statements?

A. Yes. Attached to my testimony is Statement BL, which describes the rate design for the charges under the formula rate. *See* Exhibit No. NPT-402.

Q. Does this conclude your testimony?

A. Yes.

Exhibit No. NPT-401

Revenue Impact Statements for the First Year of Commercial Operation

Northern Pass Transmission LLC's
Total Annual Estimated Revenue Requirements - NPT Line
Projected First Calendar Year In-Service beginning January 1, 2016

The calculation represents an annual estimate of the first full calendar year after commercial operation, and assumes the calendar year begins on January 1, 2016. Transmission Investment Base reflects a beginning and end of year average.

Line No.	I. TRANSMISSION INVESTMENT BASE	Attachment B Reference Section:		Estimated	
1	Transmission Plant	III(A)(1)(i)	$	1,107,000,000	A
2	General Plant	III(A)(1)(ii)		-	B
3	Intangible Plant	III(A)(1)(iii)		-	B
4	Plant Held for Future Use	III(A)(1)(iv)		-	C
5	Total Plant *(sum of Lines 1 through 4)*		$	1,107,000,000	
6	Depreciation Reserve	III(A)(1)(v)		13,642,000	
7	Accumulated Deferred Income Taxes	III(A)(1)(vi)		11,901,000	
8	Net Investment *(Lines 5 - 6 - 7)*		$	1,081,457,000	
9	Regulatory Asset - Pre-COD Expenses	III(A)(1)(vii)		-	D
10	Prepayments	III(A)(1)(viii)		-	E
11	Plant Materials and Supplies	III(A)(1)(ix)		8,500,000	
12	Cash Working Capital	III(A)(1)(x)		437,500	
13	Total Transmission Investment Base *(sum of Lines 8 through 12)*		$	1,090,394,500	
	II. REVENUE REQUIREMENTS				
14	Return on Equity	III(A)	$	68,476,775	
15	Return on Long-term Debt	III(B)		42,089,228	
16	Federal Income Taxes associated with Return on Equity	III(C)		38,584,700	
17	State Income Taxes associated with Return on Equity	III(D)		10,240,985	
18	Depreciation Expense	III(E)		27,284,000	
19	Amortization of Investment Tax Credits	III(F)		-	F
20	Municipal Tax Expense	III(G)		25,500,000	
21	Payroll Tax Expense	III(H)		-	E
22	Operation and Maintenance Expense (O&M)	III(I)		3,000,000	
23	Transmission Administrative and General Expense (A&G)	III(J)		4,000,000	
24	Taxes and Fees Charge	III(K)		-	F
25	Right-of-Way (Rental) Expense	III(L)		-	E
26	Scheduling, System Control and Dispatch Service Expense	III(M)		-	E
27	Amortization of Regulatory Asset – Pre-COD Expenses	III(N)		-	D
28	Levelized Annual Decommissioning Payment	III(O)		-	E
29	Transmission Support Expense	III(P)		-	G
30	Miscellaneous Revenues (such as Rents Received from Electric Property)	III(Q)		-	E
31	Total Revenue Requirements *(sum of Lines 14 through 30)*		$	219,175,688	

A Transmission Plant estimate includes both the DC and AC Cost, land, accrued AFUDC and capitalized property taxes.

B Currently, Transmission Plant balance estimate reflects all plant assets. Once the project is in-service, certain of the plant assets may be recorded as either general plant or intangible plant. These estimates are not available at this time.

C Current expectation is that all land, easements, and plant will be placed in service at the commercial operation date, and therefore, no Plant Held for Future Use will be recorded.

D This account is currently estimated to be zero. We anticipate this to be immaterial during construction.

E These balances are assumed to be zero, as no estimates are currently available.

F Currently, these investments are not expected to qualify for Investment Tax Credits, and therefore, no amortization of ITCs are noted above. In addition, the term "Taxes and Fees Charge" is intended to include any taxes or fees that may be imposed by any Governmental Authority on service provided by NPT, as defined in Attachment B of the TSA. Currently, this amount is estimated to be zero.

G No estimate is available at this time. If support agreements are required, associated expenses will then be recorded, as applicable.

Northern Pass Transmission LLC
Calculation of Investment Return and Taxes
2016 Year

	(A) X CAPITALIZATION RATIOS	(B) Y COST OF CAPITAL	(C) = (A) x (B) WEIGHTED COST OF CAPITAL	(D) EQUITY PORTION
1 LONG-TERM DEBT	50.00%	7.71%	3.86%	
2 PREFERRED STOCK	0.00%	0.00%	0.00%	0.00%
3 COMMON EQUITY	50.00%	12.56%	6.28%	6.28%
4 Total Investment Return *(lines 1 + 2 + 3)*	100.00%		10.14%	6.28%
5 Return on Equity (excluding taxes)	**6.28%**			
6 Return on Long-term Debt	**3.86%**			

7 Federal Income Taxes associated with Return on Equity = (R.O.E. + (Amortization of (Inv. Tax Credit + Z Equity AFUDC in Depreciation Exp.) / Total Inv. Base) x Federal Income Tax Rate) / (1 - Federal Income Tax Rate)

= (6.28% +(- + 3,180,775) / 1,090,394,500) x 35.0%) / (1 - 35.0%)

= **3.54%**

8 State Income Taxes associated with Return on Equity = (R.O.E. + (Amortization of (Inv. Tax Credit + Equity AFUDC in Depreciation Exp.) / Total Inv. Base) + Federal Income Tax)* State Income Tax Rate / (1 - State Income Tax Rate)

= (6.28% +(- + 3,180,775) / 1,090,394,500) + 3.54%)* 8.5% / (1 - 8.5%)

= **0.94%**

9 Cost of Capital Rate *(lines 5 + 6 + 7 + 8)* = **14.618%**

	Return on Equity	Return on Long-term Debt	Federal Income Taxes	State Income Taxes	TOTAL
10 INVESTMENT BASE	$ 1,090,394,500	$ 1,090,394,500	$ 1,090,394,500	$ 1,090,394,500	$ 1,090,394,500
11 Associated Rate (from Lines 5 through 8)	6.28%	3.86%	3.54%	0.94%	14.618%
12 Investment Return and Income Taxes (lines 10 x 11)	$ 68,476,775	$ 42,089,228	$ 38,584,700	$ 10,240,985	**$ 159,391,688**

Notes:

(D) Represents only the Equity portion of the Weighted Cost of Capital (Preferred Stock + Common Equity); this also equals the Return on Equity (R.O.E.) used in the calculations above.

X Capitalization ratios are in accordance with Section 8.3 of the TSA.

Y Estimated cost of debt rate based on NU's current financial forecasts. Return on Equity (ROE) is based on current ROE per Section 8.4 of the TSA.

Z Equity AFUDC of Depreciation Expense is calculated based on the current estimated project costs, current ROE (Section 8.4), and assumed capital structure (Section 8.3).

NORTHERN PASS TRANSMISSION LLC'S
ESTIMATED MONTHLY REVENUES – HQ HVDC LINE
Projected First Calendar Year In-Service beginning January 1, 2016

Month	Revenue
January	$18,264,641
February	$18,264,641
March	$18,264,641
April	$18,264,641
May	$18,264,641
June	$18,264,641
July	$18,264,641
August	$18,264,641
September	$18,264,641
October	$18,264,641
November	$18,264,641
December	$18,264,641

Exhibit No. NPT-402

Statement BL

Statement BL

HQ Hydro Renewable pays a monthly charge designed to recover one-twelfth of the annual revenue requirement associated with the Northern Pass Transmission Line ("NPT Line") and AC Upgrades, as determined under a formula rate included in the Transmission Service Agreement. The formula rate recovers a return on Northern Pass's investment in the NPT Line plus associated income taxes, depreciation expense, operation and maintenance expenses, and other expenses associated with the NPT Line (including the AC Upgrade costs). The formula rate provides for Northern Pass to forecast the revenue requirement for each calendar year and charge the resulting rates in that calendar year, subject to true-up with interest in the following year. One hundred percent of the annual revenue requirement for the NPT Line and AC Upgrades is allocated to HQ Hydro Renewable.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	)))	**Docket No. ER11-___-000**

VERIFICATION

State of Connecticut)
) ss. Berlin
County of Hartford)

I, Paula M. Taupier, am submitting this testimony in the above-captioned proceeding for Northern Pass Transmission LLC. My business address is Northeast Utilities Service Company, 107 Selden Street, Berlin, Connecticut 06037. I submit this verification to verify that the Prepared Direct Testimony of Paula M. Taupier was prepared by me, with the assistance of others working under my direction and supervision, and that the contents are true to the best of my knowledge, information and belief. Executed in Berlin, Connecticut this 15th day of December, 2010.

Paula M. Taupier

SUBSCRIBED AND SWORN to before me
on this 15th day of December, 2010.

Notary Public

My commission expires: My Commission Expires March 31, 2014

Appendix E

Direct Testimony of Timothy J. Griffin
Exhibit No. NPT-500

Exh. No. NPT-500

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	**)**	**Docket No. ER11-___-000**

PREPARED DIRECT TESTIMONY OF TIMOTHY J. GRIFFIN

December 15, 2010

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	)	Docket No. ER11-_____
	)	
	)	

PREPARED DIRECT TESTIMONY OF
TIMOTHY J. GRIFFIN
ON BEHALF OF NORTHERN PASS TRANSMISSION LLC

I. INTRODUCTION AND EXPERIENCE

Q. Please state your name and business address.

A. My name is Timothy J. Griffin. My business address is 56 Prospect Street, Hartford, Connecticut, 06103.

Q. Please describe your educational background and employment experience.

A. I graduated from Fairfield University with a Bachelor's degree in Accounting. I began my career at Arthur Andersen LLP and worked there for approximately 10 years during which time I became a Certified Public Accountant. I held the title of Experience Manager prior to leaving Arthur Andersen LLP to join Northeast Utilities ("NU"). I held the position of Assistant Controller – Corporate Accounting for three years at NU. I then became the Controller of Select Energy Inc. ("Select Energy"), which is an

indirect subsidiary of NU. During the wind down and divestiture of Select Energy's businesses, I returned to the position of Assistant Controller – Corporate Accounting about one year later. In August of 2010, I moved into a new role as Assistant Controller – Corporate Budgeting and Reporting for NU.

Q. What were your areas of responsibility as Assistant Controller – Corporate Accounting that are relevant to your testimony?

A. As Assistant Controller – Corporate Accounting, I was responsible for SEC and FERC financial reporting, closing the books, technical accounting research, Sarbanes-Oxley compliance, and corporate budgeting.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to support the Northern Pass Transmission LLC ("Northern Pass") filing with the Commission of its Transmission Service Agreement ("TSA") with H.Q. Hydro Renewable Energy, Inc. ("HQ Hydro Renewable") and the accompanying accounting treatment. In that context, I describe the services that Northeast Utilities Service Company ("NUSCO") will provide to Northern Pass, how those services will be billed, and Northern Pass's proposed accounting. I also describe the capital funding and related accounting, income tax matters related to Northern Pass, and accounting for costs of asset removal/decommissioning,

as well as regulatory assets related to (1) costs incurred prior to commercial operation and (2) costs of asset removal/decommissioning.

II. NUSCO'S SERVICES TO NORTHERN PASS

Q. What is NUSCO?

A. NUSCO is a service company subsidiary of NU that provides various corporate services to NU subsidiaries, including Commission-jurisdictional subsidiaries, at cost pursuant to standardized service agreements.

Q. What services will NUSCO provide to Northern Pass?

A. Northern Pass is a newly created entity that will have access to the utility expertise and the services it requires through a service agreement with NUSCO. To the extent that Northern Pass asks NUSCO to do so, NUSCO will provide Northern Pass general management services, such as executive, administrative, managerial, coordinating and advisory services. NUSCO will also provide other functions and activities, such as corporate and secretarial, financial planning, accounting and taxes, legal, insurance, budgeting, data processing, engineering research and standardization, and other administrative services. NUSCO has entered into a service contract, dated April 1, 2010, with Northern Pass for the provision of these services. The expertise of NUSCO's employees in transmission and utility matters, as well as the economies of scale NUSCO can achieve, will enable NUSCO to provide those services effectively and efficiently. The provision of

services by NUSCO at cost is consistent with Commission policy and will benefit both Northern Pass and HQ Hydro Renewable, the customer under the TSA.

Q. How will costs be billed to Northern Pass?

A. As indicated above, NUSCO will bill Northern Pass for the costs of services rendered pursuant to the service agreements. Costs associated with contracts Northern Pass has with third-party vendors will be paid directly by Northern Pass.

Q. Can you describe the administrative and general expenses Northern Pass is likely to incur?

A. The administrative and general expenses for Northern Pass are expected to come from two sources: (1) Northern Pass direct expenses, and (2) NUSCO billings. The Northern Pass direct expenses will consist primarily of third-party (non-affiliate) contracts for services entered into directly by Northern Pass. The expenses billed to Northern Pass from NUSCO will consist primarily of services described earlier in my testimony.

Q. How will NUSCO costs be charged to Northern Pass?

A. The services provided by NUSCO employees and charged to Northern Pass will fall into two categories: direct and allocated. We expect that most costs will be directly charged to Northern Pass due to the limited scope of Northern Pass as a single asset entity. As discussed below, the costs billed

or charged to Northern Pass by NUSCO will include overheads. No mark-up will be charged.

NUSCO costs of capital are based on the components of the capital structure and the costs of those components. The costs of capital will then be included in overhead costs and charged to Northern Pass along with amounts directly or indirectly charged to Northern Pass.

The directly-charged costs are those costs for work done by NUSCO employees directly for and caused by Northern Pass. The services are provided to Northern Pass at cost, which is the same basis as services provided to other NUSCO affiliates. Northern Pass will be billed based on the hourly rate and appropriate overhead loading factors for the employees providing service to Northern Pass. The same overhead loading factors will be used for billings to Northern Pass that are used for all affiliate billings.

To the extent this is applicable, allocated costs are those that are billed to multiple affiliates using an allocation formula that is intended to allocate costs based on cost drivers. These are costs that, due to their shared nature, are not directly billed to an individual affiliate. Examples of services whose costs are allocated or shared are some types of information technology, purchasing, human resources, finance, accounts payable, strategic planning, business logistics and internal support services. These costs are allocated to the affiliates based on cost drivers. The cost drivers

applicable to services such as those listed above are determined by the personnel who manage the costs of those services, and the cost drivers are updated, reviewed, and approved on an annual basis. For example, some information technology costs are allocated based on the number of personal computers used by the businesses.

Q. Will any other NU companies provide services to Northern Pass?

A. Yes. It is likely that certain employees of Public Service Company of New Hampshire (a subsidiary of NU) will provide services to Northern Pass. These services will be provided and billed to Northern Pass at cost, including overheads.

III. ACCOUNTING

Q. How will NU and NSTAR record equity contributions and accounting transactions?

A. Northern Pass is an indirect subsidiary of NU (75 percent owner) and NSTAR (25 percent owner). NU and NSTAR will record contributions made to Northern Pass on their respective balance sheets as investments in a subsidiary. Northern Pass will record the receipt of these contributions as equity on its balance sheet and maintain separate capital accounts for NU and NSTAR. All of the transactions for Northern Pass will be recorded on Northern Pass's books, which will be a separate set of books and records

from NU and NSTAR. Consequently, Northern Pass's books and records will reflect its assets, liabilities and results of operations.

Q. Will Northern Pass record income taxes?

A. Northern Pass is a pass-through entity for federal income tax purposes and will not record federal income taxes on its books and records in conformity with Generally Accepted Accounting Principles ("GAAP"). For state income tax purposes, Northern Pass is a New Hampshire corporation that is subject to state income taxes in New Hampshire. Those state income taxes will be recorded on the books of Northern Pass in accordance with GAAP. For FERC reporting purposes, Northern Pass will be treated as a separate entity that is subject to all taxes, consistent with Commission accounting policy.

Q. Where will the federal income taxes resulting from the ownership and operations of Northern Pass be recorded?

A. Northern Pass is owned by NU and NSTAR. NU and NSTAR will each record their respective share of Northern Pass's results for federal income tax purposes and will be required to pay any resulting income taxes.

Q. Given that Northern Pass will not record federal income taxes on its books, are there provisions that will allow for the recovery of income taxes?

A. Yes. The TSA with HQ Hydro Renewable allows for the recovery of federal and state income taxes either incurred by Northern Pass or by NU or NSTAR. This is consistent with FERC policy as well. On May 4, 2005, the Commission, in Docket No. PL05-5-000, ruled that pass-through entities will be allowed an income tax allowance. The Commission stated in its conclusion

> "…that it should return to its pre-*Lakehead* policy and permit an income tax allowance for all entities or individuals owning public utility assets, provided that an entity or individual has an actual or potential income tax liability to be paid on that income from those assets. Thus a tax-paying corporation, a partnership, a limited liability corporation, or other pass-through entity would be permitted an income tax allowance on the income imputed to the corporation, or to the partners or the members of pass-through entities, provided that the corporation or the partners or the members, have an actual or potential income tax liability on that public utility income. Given this important qualification, any pass-through entity seeking an income tax allowance in a specific rate proceeding must establish that its partners or members have an actual or potential income tax obligation on the entity's public utility income."

Inquiry Regarding Income Tax Allowances, Policy Statement, 111 FERC ¶ 61,139 at P 32 (2005).

Q. Do NU and NSTAR have a federal tax liability as a result of their ownership of this pass-through entity?

A. Yes. NU and NSTAR are corporations liable for federal income taxes related to their ownership of Northern Pass. Therefore, Northern Pass falls within the FERC requirements that allow for the use of an income tax allowance.

Q. How will NU and NSTAR record the results of Northern Pass's operations?

A. After Northern Pass closes its books each month, the capital accounts of NU and NSTAR will be adjusted to reflect the net income or net loss of Northern Pass. NU and NSTAR will then adjust their respective investment balances in Northern Pass to recognize the change in their capital accounts. Additionally, NU as a majority owner and the entity that essentially controls Northern Pass will consolidate Northern Pass when it reports its balance sheets and income statements. This means that all of Northern Pass's revenues, expenses, assets, and liabilities will be included in NU's consolidated financial statements. The non-controlling interest represented by NSTAR's 25 percent ownership will be presented separately by NU in the consolidated income statement and in the equity section of the NU consolidated balance sheet.

Q. Will this accounting be affected by the NU and NSTAR merger that was recently announced?

A. Yes. If the merger is completed as announced, then NU will own 100 percent of Northern Pass and will consolidate it for accounting purposes. At the time of the merger the Northern Pass legal entity and ownership percentages will continue to exist. However, the non-controlling interest from NSTAR's 25 percent ownership that is described above will no longer be needed when the new combined entity reports its balance sheets and income statements.

Q. How will NU and NSTAR record receipt of dividend payments or returns of capital?

A. When Northern Pass pays distributions in the form of dividends or returns of capital to NU and NSTAR, the payments will reduce the equity of Northern Pass by the amount of the distribution. Northern Pass will reduce each owner's capital account by the appropriate amount of the distribution based on ownership percentages, and it is expected that each owner will reduce its investment balance in Northern Pass to reflect any distributions received.

Q. Please describe Northern Pass's proposed accounting for, and recovery of, pre-commercial operation costs.

A. Northern Pass has already incurred some direct costs, such as the cost of attorneys and consultants, and will continue to incur costs prior to the project's Commercial Operation Date ("COD"). Also, NU, as the main service provider to Northern Pass, has incurred and will continue to incur both third party costs and internal costs attributable to those services. As these costs relate to the construction of the Northern Pass Transmission project (along with engineering design, siting, permitting costs, etc.), most of these costs will be included in Account 107 – Construction Work in Progress and recovered through the formula rate once the project commences commercial operation. Northern Pass and HQ Hydro Renewable have also agreed that other costs and expenses that do not meet the requirements to be included in Construction Work in Progress (i.e., those not included in Account 107) will be deferred until the project enters commercial operation and then recovered from HQ Hydro Renewable. This specifically excludes contract negotiation costs but may include AC upgrade costs invoiced to and paid by Northern Pass prior to commercial operations and routine costs associated with operating Northern Pass during this period, such as accounting, cash management, and other administrative work. This could also include property tax expense on land that is held for

future use. These costs and expenses are referred to in the TSA as "Pre-COD Expenses." (TSA Article 8)

Accordingly, Northern Pass requests permission to defer its Pre-COD expenses as a regulatory asset until the project enters commercial operation. Northern Pass further proposes to be allowed to recover the time value of these deferred Pre-COD expenses by calculating a carrying cost on such costs pending future recovery. These deferred expenses and associated carrying costs would be recorded as a Regulatory Asset in Account 182.3 in accordance with applicable regulatory asset accounting. The deferred expenses and carrying charges would be amortized to expense commensurate with their recovery over a three-year period commencing on the COD of the project.

Q. How will costs other than constructions expenditures be recorded and recovered through the formula rate?

A. After the project enters commercial operation and cost recovery begins, it is expected that all costs other than construction expenditures will be expensed as incurred or will be accounted for in accordance with applicable accounting guidance. These costs will be included in the formula rate and recovered from HQ Hydro Renewable.

Q. Does Northern Pass expect that it will be required to decommission the Northern Pass facilities?

A. The obligation to decommission some or all of the Northern Pass facilities could be imposed on Northern Pass by law at any time. In such event, an asset retirement obligation ("ARO") would exist with respect to such assets.

Q. If decommissioning is required, will Northern Pass record an ARO in connection with the decommissioning of the project, and if so, how?

A. In the event that all or a portion of the project is required to be removed by applicable law, Northern Pass will record an ARO. Amounts associated with that ARO will be recorded in accordance with the Commission's Order No. 631 and the Commission's General Instruction 25, with the obligation included in Account 230 and the asset in Account 101.1. This would occur at the time the ARO is established, which would likely be during or shortly after the completion of construction. Over the course of the operation of the Northern Pass line, the asset will be depreciated and the ARO will be accreted to its future value.

Q. If an ARO is recorded, would Northern Pass record a regulatory asset for the expenses related to the ARO?

A. Yes. As discussed below, the TSA provides for the recovery of the cost of decommissioning. The Commission's approval of the TSA provides the

basis for recording and maintaining the regulatory asset. The regulatory asset will represent the amount that will be recovered during the last five years of the contract, also as discussed below.

However, through this filing Northern Pass is requesting permission to establish such regulatory asset in the event that the Commission determines such permission is required.

Q. How would the regulatory asset be created?

A. The regulatory asset would be created by deferring incurred costs related to the ARO. These costs include depreciation of the ARO asset and accretion of the ARO liability.

Q. Is Northern Pass requesting permission to include this regulatory asset in rate base?

A. No. Northern Pass is not including the regulatory asset itself in rate base. The ARO asset, the regulatory asset, and the ARO are expected to offset each other, and all of these accounts will be excluded from rate base and accordingly will not earn a return. The ARO asset, the regulatory asset, and the ARO recorded for book purposes are not expected to have income tax bases, and no deferred income tax impacts are expected in total. However, since the book to tax differences on the ARO asset, the regulatory asset, and the ARO may not totally offset at times, there may be an impact on the calculation of Total Accumulated Deferred Income Taxes ("Total ADIT"),

as that term is defined in the formula rate. In such circumstances, the formula rate provides for excluding from Total ADIT, which is in rate base, amounts related to the ARO asset, the regulatory asset, and the ARO.

Q. What is the amortization period of the regulatory asset that will be created?

A. In accordance with Article 9 of the TSA, the regulatory asset will be amortized over the last five years of the TSA.

Q. Does the TSA recognize the possibility of the creation of an ARO or the possibility of decommissioning without the existence of an ARO with respect to the Northern Pass Facilities?

A. Yes. The TSA provides for the possibility that there may be an ARO associated with all or a portion of the Northern Pass facilities and provides for the recovery of the cost of required decommissioning. It is possible, however, that the Northern Pass facilities will be decommissioned at the end of their useful life without a legal requirement to do so. This would result in decommissioning costs without the existence of an ARO, and these costs would be expensed as incurred and recovered by Northern Pass from HQ Hydro Renewable through the formula rate if approved by Northern Pass's management committee.

Q. How will the costs of required decommissioning be recovered from HQ Hydro Renewable?

A. The TSA generally provides for Northern Pass to recover from HQ Hydro Renewable, over the last five years of the forty-year term, the estimated costs of required decommissioning, net of salvage (the "Net Decommissioning Costs"), subject to true-up after decommissioning activities have been completed. Northern Pass's recovery of these costs is accelerated in certain circumstances. For example, if the TSA is terminated early due to HQ Hydro Renewable's default, then decommissioning costs are not recovered under the formula rate and HQ Hydro Renewable will pay an estimated decommissioning cost subsequent to the termination in a lump sum, subject (absent a Subsequent Use of the project) to true-up and prudency challenges for costs above or salvage proceeds below the approved decommissioning plan.

Q. Please explain the TSA provisions providing for the recovery of decommissioning costs over the last five years of the TSA.

A. The amount billed to HQ Hydro Renewable for Net Decommissioning Costs during the last five years of the TSA will be based on the monthly amount needed to arrive at the estimated Net Decommissioning Costs at the end of the term of the TSA. This monthly amount is referred to in the TSA as the Levelized Monthly Decommissioning Payment. The Levelized

Monthly Decommissioning Payment will be calculated using present value techniques, and the discount rate used will be the assumed rate of return earned on the Levelized Monthly Decommissioning Payments collected from HQ Hydro Renewable. (TSA Article 9)

Separately, by the end of the term of the TSA, the ARO will have been accreted to its future value, the ARO asset will have been fully depreciated and the ARO regulatory asset will have been fully amortized, as the estimated decommissioning costs will have been collected from HQ Hydro Renewable. During the process of decommissioning or thereafter, shortfalls or excess collections will be trued-up and collected from or refunded to HQ Hydro Renewable.

Q. Does this conclude your testimony?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	)))	**Docket No. ER11-___-000**

VERIFICATION

State of Connecticut)
) ss.
County of Hartford)

I, Timothy J. Griffin, am submitting this testimony in the above-captioned proceeding for Northern Pass Transmission LLC. My business address is 56 Prospect Street, Hartford, Connecticut 06103. I submit this verification to verify that the Prepared Direct Testimony of Timothy J. Griffin was prepared by me, with the assistance of others working under my direction and supervision, and that the contents are true to the best of my knowledge, information and belief. Executed in Hartford, Connecticut this 15th day of December, 2010.

Timothy J. Griffin

SUBSCRIBED AND SWORN to before me
on this 15 day of December, 2010.

Cynthia L Perry

Notary Public

My commission expires: 6/2011

Appendix F

Direct Testimony and Exhibits of William E. Avera

Exhibit No. NPT-600

THE UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	**Docket No. ER11-___-000**

PREPARED DIRECT TESTIMONY OF WILLIAM E. AVERA ON BEHALF OF NORTHERN PASS TRANSMISSION LLC

December 15, 2010

Exhibit No. NPT-600

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Exhibit No. NPT-600

EXHIBITS TO DIRECT TESTIMONY

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NPT-604	"br + sv" Growth Rate – National Proxy Group
NPT-605	FERC DCF Model – Regional Proxy Group
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NPT-609	"br + sv" Growth Rate – Non-Utility Proxy Group
NPT-610	Capital Asset Pricing Model
NPT-611	Expected Earnings Approach
NPT-612	Capital Structure
NPT-613	Summary of Cost of Equity Estimates
NPT-614	Workpapers

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am the President of FINCAP, Inc., a firm providing financial, economic, and policy consulting services to business and government.

A. Qualifications

Q. WHAT ARE YOUR QUALIFICATIONS?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas ("PUCT") as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory

1 Commission ("FERC" or the "Commission"), as well as the Federal
2 Communications Commission ("FCC"), the Surface Transportation Board (and its
3 predecessor, the Interstate Commerce Commission), the Canadian Radio-
4 Television and Telecommunications Commission, and regulatory agencies,
5 courts, and legislative committees in over 40 states.

6 In 1995, I was appointed by the PUCT, with the approval of the Governor,
7 to the Synchronous Interconnection Committee to advise the Texas legislature on
8 the costs and benefits of connecting Texas to the national electric transmission
9 grid. In addition, I served as an outside director of Georgia System Operations
10 Corporation, the system operator for electric cooperatives in Georgia.

11 I have served as Lecturer in the Finance Department at the University of
12 Texas at Austin and taught in the evening graduate program at St. Edward's
13 University for twenty years. In addition, I have lectured on economic and
14 regulatory topics in programs sponsored by universities and industry groups. I
15 have taught in hundreds of educational programs for financial analysts in
16 programs sponsored by the Association for Investment Management and
17 Research, the Financial Analysts Review, and local financial analysts societies.
18 These programs have been presented in Asia, Europe, and North America,
19 including the Financial Analysts Seminar at Northwestern University. I hold the
20 Chartered Financial Analyst (CFA®) designation and have served as Vice
21 President for Membership of the Financial Management Association. I have also
22 served on the Board of Directors of the North Carolina Society of Financial
23 Analysts. I was elected Vice Chairman of the National Association of Regulatory
24 Utility Commissioners ("NARUC") Subcommittee on Economics and appointed
25 to NARUC's Technical Subcommittee on the National Energy Act. I have also

served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Exhibit No. NPT-601.

B. Overview

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. In connection with the development of the Northern Pass Transmission Line (the "NPT Line"), Northern Pass Transmission LLC ("Northern Pass" or "the Company") has entered into a bilateral cost-based transmission service agreement ("TSA"). The TSA specifies that Northern Pass will apply a 12.56 percent return on equity ("ROE") to calculate Allowance for Funds Used During Construction during the construction period. Upon commercial operation of the NPT Line, the ROE will be adjusted, if necessary, to be equal to the then-effective base ROE approved for regional transmission service under the Open Access Transmission Tariff approved for ISO New England, Inc. ("ISO-NE"), plus an adder of 142 basis points, which is equivalent to an adder of 50 basis points for participation in a regional transmission organization ("RTO"), plus an incentive adder of 92 basis points for investment in new transmission infrastructure.

The purpose of my testimony is to present to the Commission my independent analysis of a fair ROE range of reasonableness for this new transmission project, which is discussed in detail in the testimony of James A. Muntz, Mr. Michael J. Auseré, and Mr. Geoffrey O. Lubbock. My evaluation considered FERC's established precedent and policy objectives, industry conditions and fundamentals, independent estimates of the ROE for benchmark groups of electric utilities and non-utility firms, as well as the particular exposures confronting the Company.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. In connection with the present filing, I considered and relied upon corporate disclosures, publicly available financial reports and filings, and other published information relating to Northern Pass and the NPT Line. In addition, I am familiar with FERC policy generally and have submitted testimony in numerous proceedings at the Commission dealing with required rates of return for electric utilities. I also reviewed information relating generally to capital markets and specifically to investor perceptions, requirements, and expectations for regulated utilities in a restructured wholesale electric power market. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of ROE issues affecting Northern Pass and are the basis of my conclusions.

Q. WHAT IS THE ROLE OF THE RETURN ON EQUITY IN SETTING A UTILITY'S RATES?

A. The rate of return on common equity compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield* [1] and *Hope* [2] cases, a

[1] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923).

utility's allowed return on common equity should be sufficient to: (1) fairly compensate investors for capital they have invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. HOW DID YOU EVALUATE THE ROE RANGE OF REASONABLENESS FOR NORTHERN PASS?

A. I first reviewed the operations and finances of Northern Pass, as well as the general conditions in the electric utility industry. With this background, I examined current capital market conditions and conducted various quantitative analyses to estimate the current cost of equity. Consistent with Commission precedent,[3] I relied on the Discounted Cash Flow ("DCF") methodology currently prescribed by FERC, and applied it to a national proxy group of other electric utilities with comparable investment risks to Northern Pass. In addition, I examined DCF results for geographical proxy groups with a direct correlation to Northern Pass and the broader markets in which the Company will operate, as well as alternative ROE benchmarks that included DCF cost of equity estimates for a proxy group of low-risk industrial firms, applications of the Capital Asset Pricing Model ("CAPM"), and expected earned rates of return for utilities.

(. . . continued)

[2] *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

[3] *See, e.g.*, *Southern California Edison Co.,* 131 FERC ¶ 61,020 (2010) (*SoCal Edison*)*; Bangor Hydro-Elec. Co.*, *et al.,* 117 FERC ¶ 61,129 (2006) ("*Bangor Hydro*"); *Midwest Indep. Transmission Sys. Operator*, *Inc.*, 100 FERC ¶ 61,292 (2002) ("*Midwest ISO*"), *reh'g denied*, 102 FERC ¶ 61,143 (2003), *modified on other grounds sub nom. Pub. Serv. Comm'n v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005); *S. Cal. Edison Co.*, 92 FERC ¶ 61,070 (2000) ("*Southern California Edison*"), *reh'g denied*, 108 FERC ¶ 61,085 (2004).

C. Summary and Conclusions

Q. BASED ON YOUR EVALUATION, WHAT DID YOU CONCLUDE REGARDING THE ROE BEING REQUESTED FOR NORTHERN PASS?

A. It is my conclusion that the 12.56 percent initial ROE specified in the TSA and requested by Northern Pass is reasonable and should be approved. Based on my analyses and evaluation, I conclude that this is a reasonable incentive ROE for the NPT Line. The bases for my conclusion are summarized below:

- This ROE falls well within the 7.7 percent to 16.4 percent zone of reasonableness produced by applying the Commission-approved DCF approach to a national proxy group of risk-comparable electric utilities and a group of utilities operating in adjacent FERC-approved Regional Transmission Organizations, as well as the 8.6 percent to 16.4 percent zone of reasonableness produced after narrowing the regional proxy group based on comparable credit ratings;
- In accordance with *Order Nos. 679* and *679-A*, the 12.56 percent ROE requested for the NPT Line falls well within the upper end of the DCF range implied by my proxy group results;
- Because an incentive ROE from the upper end of the reasonable DCF range is warranted for Northern Pass, there is no reason to determine a point estimate from within the zone of reasonableness by reference to either the midpoint or median; and,
- My conclusions are reinforced by the need to consider flotation costs, and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond. Moreover, the potential for turmoil in the domestic and global financial markets and continued economic uncertainties exacerbate the risks faced by utilities and their investors.

Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN EVALUATING YOUR RECOMMENDATION IN THIS CASE?

A. My recommendation was reinforced by the following findings:

- Sensitivity to regulatory uncertainties has increased dramatically and investors recognize that constructive regulation is a key ingredient in maintaining utility credit standing and financial integrity;

- The NPT Line must compete for investors' capital with other utilities and businesses of comparable risk. If Northern Pass is not provided an opportunity to earn a return that is sufficient to compensate for the underlying risks, investors will be unwilling to supply capital;
- The allowed ROE for Northern Pass must reflect the need to provide returns that are sufficient to meet the established policy goal of encouraging participation in approved Regional Transmission Organizations, promoting capital investment in transmission, and encouraging the deployment of advanced technologies, while recognizing investors' renewed focus on the associated risks, including the significant obstacles specific to the NPT Line; and,
- As the Company's witnesses have documented, the complexities of construction and scope of the investment with the NPT Line, Northern Pass' status as a start-up entity, and the fact that it will own a single-purpose facility serving a single, foreign customer present substantial risks and challenges. An ROE from the upper end of the range of reasonableness is consistent with these special risks, reliance on advanced technologies, established Commission precedent, and the need to establish reasonable credit standing for Northern Pass.

Taken together, these considerations support an ROE for Northern Pass from the upper end of the DCF zone of reasonableness and confirm my conclusion that the 12.56 percent requested ROE is reasonable.

Q. WHAT IS YOUR CONCLUSION AS TO THE REASONABLENESS OF THE COMPANY'S CAPITAL STRUCTURE?

A. I endorse the capital structure employed by Northern Pass, which is consistent with established Commission precedent and the range of capitalizations maintained by the firms in my utility proxy groups, especially when considering the trends towards lower debt leverage, the Company's lack of operating history, and the need to establish and maintain an investment grade credit standing going forward.

II. FUNDAMENTAL ANALYSES

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. As a predicate to the quantitative analyses that I address later in this testimony, this section briefly reviews the operations and finances of Northern Pass. In addition, it examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of the fundamental factors driving the risks and prospects of electric utilities is essential in developing an informed opinion of investors' expectations and requirements that are the basis of a fair rate of return.

A. Northern Pass Transmission LLC

Q. PLEASE BRIEFLY DESCRIBE NORTHERN PASS.

A. Northern Pass is a joint venture between NU Transmission Ventures, Inc., a wholly owned subsidiary of Northeast Utilities ("NU") – and NSTAR Transmission Ventures, Inc., which is wholly owned by NSTAR. Northern Pass was formed to develop, construct, own, and maintain the U.S. portion of the NPT Line.

Headquartered in Hartford, Connecticut, NU operates New England's largest utility system, and through its utility subsidiaries, is primarily engaged in the transmission and distribution of electricity within portions of Connecticut, New Hampshire, and western Massachusetts. NU also furnishes natural gas utility service in Connecticut through its gas distribution company subsidiary. On a combined basis, NU's operating subsidiaries serve over 2.1 million utility customers in nearly 500 cities and towns, and its electric transmission systems consist of over 3,400 miles of overhead and underground lines. At year-end 2009, NU had total assets of $14.1 billion, with operating revenues amounting to approximately $5.4 billion.

NSTAR, through its NSTAR Electric Company subsidiary, supplies retail electricity in Massachusetts to a service area of approximately 1,700 square miles with a population of approximately 2.4 million. In addition to the City of Boston and 80 surrounding cities and towns, NSTAR's service territory includes the geographic area comprising Cape Cod and Martha's Vineyard. NSTAR Electric Company's transmission and distribution system consists of approximately 22,000 circuit miles of overhead lines, approximately 13,000 circuit miles of underground lines, 256 substation facilities and approximately 1.2 million active customer meters. At year-end 2009, total assets amounted to $8.1 billion, with operating revenues totaling approximately $3.1 billion. Both NU and NSTAR are members of ISO-NE.

On October 18, 2010, NU and NSTAR announced approval of a merger agreement in a stock-for-stock merger of equals. The combined company, which will be called Northeast Utilities, will operate six regulated electric and gas utilities in three states and will have nearly 3.5 million electric and gas customers.

Q. PLEASE PROVIDE A SHORT DESCRIPTION OF THE NTP LINE.

A. As described more fully in the testimony of other witnesses for Northern Pass, the NPT Line is the U.S. portion of a new high voltage direct current ("HVDC") tie line and an interconnected alternating current line that will interconnect the Hydro-Québec TransÉnergie transmission system to the ISO-NE administered New England transmission system. The NPT Line consists of approximately 140 miles of HVDC above-ground transmission line that extends from the Canadian border to a new direct current to alternating current converter terminal to be located in the City of Franklin, New Hampshire. The NPT Line also includes a radial 345-kV transmission line extending approximately 40 miles from the

southern terminus of the HVDC Line in Franklin, New Hampshire to an existing substation in Deerfield, New Hampshire. The purpose of the NPT Line is to make available up to 1,200 Megawatts of Hydro-Québec's surplus low-carbon, predominantly hydro-electric power to New England's power grid. This major source of renewable energy is expected to significantly reduce carbon dioxide emissions, increase fuel diversity, and dampen price volatility for wholesale electricity in New England.[4]

Q. BRIEFLY DESCRIBE ISO-NE.

A. Based in Holyoke, Massachusetts, ISO-NE is an independent, not-for-profit corporation established to manage the operation of most of the electric transmission assets of its member utilities. Currently, ISO-NE coordinates the movement of wholesale electricity in all or parts of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. The Commission in 2005 designated ISO-NE as the RTO for this six-state region. In its role as market operator, ISO-NE balances the needs of suppliers, wholesale customers, and other market participants and monitors market activities.

The primary objectives of ISO-NE include ensuring open access to bulk electric power lines and maintaining and enhancing transmission system reliability. While ISO-NE has authority for operational control of the transmission system, the transmission-owning members ("TOs") retain ownership and maintenance responsibility for their transmission assets and perform many operational functions under the RTO's direction. The RTO planning process seeks to identify future transmission needs for their respective regions, but the

[4] *Northeast Utilities Service Co. and NSTAR Electric Co.*, 127 FERC ¶ 61,179 at P 8 (2009).

TOs continue to bear the obligation of financing the existing system, as well as providing funds for new construction.

Q. WILL ADDITIONAL CAPITAL BE REQUIRED IN ORDER TO UNDERTAKE THE NPT LINE?

A. Most definitely. Investment in the NPT Line is expected to total approximately $1.1 billion. As explained in the testimony of Northern Pass' other witnesses, the scope and technical complexity of the NPT Line will present substantial risks. Completion of the NTP Line will require a significant capital commitment, which presents financing challenges well beyond the ordinary transmission investment.

Q. WHERE WILL THE CAPITAL TO FINANCE CONSTRUCTION OF THE NPT LINE BE OBTAINED?

A. As discussed in the testimony of Messrs. Michael J. Auseré and Geoffrey O. Lubbock, Northern Pass' investment in the NPT Line will be capitalized through a combination of equity contributions from NU and NSTAR, as well as debt financing arranged by or on behalf of Northern Pass. During construction, NU and NSTAR will periodically contribute the equity capital required to place the NPT Line into service, and Northern Pass plans to enter into a construction loan agreement for the balance of its funding needs.[5] Prior to completion of construction, Northern Pass will solicit competitive bids from potential lenders for long-term debt required to refinance the construction loan. NU and NSTAR are

[5] As discussed in greater detail in the testimony of Messrs. Auseré and Lubbock, Northern Pass anticipates that Hydro-Québec, the parent company of HQ Hydro Renewable, will provide this construction financing under terms and conditions that are customary for a project financing of this nature.

contractually obligated to provide equity capital sufficient maintain a capitalization for Northern Pass of 50 percent equity and 50 percent debt.

In addition to supporting investment in Northern Pass, NU and NSTAR will require capital investment to meet customer growth, provide for necessary maintenance and replacements of utility infrastructure, as well as fund other new investment in electric generation, transmission and distribution facilities.[6] Considering these capital requirements, maintaining the financial integrity and flexibility of the participants will be instrumental in attracting the capital necessary to fund Northern Pass in an effective manner.

Q. WHAT CREDIT RATINGS ARE ASSIGNED TO THE JOINT-VENTURE PARTICIPANTS?

A. While Northern Pass does not currently issue debt in its own name, the corporate credit ratings currently assigned to NU and NSTAR by Standard & Poor's Corporation ("S&P") are shown in Table WEA-1, below, along with the corresponding issuer ratings from Moody's Investors Service ("Moody's"), and Fitch Ratings Ltd. ("Fitch"):

[6] For example, Northeast Utilities and NSTAR have plans to invest $9 billion in New England's energy infrastructure over the next five years. "Northeast Utilities and NSTAR agree to $17.5 billion merger of equals," *News Release* (Oct. 18, 2010).

TABLE WEA-1
CORPORATE/ISSUER CREDIT RATINGS

Utility	S&P	Moody's	Fitch
NU	BBB	Baa2	BBB
NSTAR	A+	A2	A-

Following the merger announcement, both S&P and Fitch placed the ratings of NU under review for a possible upgrade, while indicating that NSTAR's ratings will be downgraded if the merger transaction is completed.[7] As S&P concluded, "The negative CreditWatch listing on NSTAR reflects that its ratings will be lowered once the [merger] transaction is completed.[8] While affirming its current ratings for NU and NSTAR, Moody's concluded that consolidated financial metrics for the combined entity would place its ratings "within the Baa rating category."[9] A "BBB" rating also reflects target financial metrics for Northern Pass, which will seek to maintain a credit rating at least one notch above minimum investment grade. This is consistent with the Commission's determination that a triple-B rating is a "minimum investment rating for an electric utility."[10]

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[7] *See, e.g.*, Standard & Poor's Corporation, "Northeast Utilities Placed On Watch Positive And NSTAR On Watch Negative On Planned Merger," *RatingsDirect* (Oct. 18, 2010).
[8] Standard & Poor's Corporation, "Northeast Utilities Placed On Watch Positive And NSTAR On Watch Negative On Planned Merger," *RatingsDirect* (Oct. 18, 2010).
[9] Moody's Investors Service, "Announcement: Moody's affirms ratings of Northeast Utilities and NSTAR following merger announcement," *Global Credit Research* (Oct. 18, 2010).
[10] *Duquesne Power & Light Co.*, 118 FERC ¶ 61,087 at P 53 (2007).

B. Electric Power Industry

Q. WHAT GENERAL CONDITIONS HAVE CHARACTERIZED THE ELECTRIC POWER INDUSTRY?

A. Since the 1990s, the industry has experienced significant structural change resulting from market forces and regulatory initiatives. At least initially, this process was largely driven by regulatory reforms at the federal level. The Energy Policy Act of 1992 greatly facilitated competition for the production and sale of power at the wholesale level, with FERC being a proponent of actions designed to foster greater competition in markets for wholesale power supply.

In April 1996, the Commission adopted *Order No. 888*,[11] which mandated open access to the wholesale transmission facilities of jurisdictional electric utilities. The Commission later promoted improvements to the transmission system and has continued to pursue the goal of creating "seamless" wholesale power markets that facilitate transactions across transmission grid boundaries, among other objectives. In response to the passage of the Energy Policy Act of 2005 ("EPAct 2005"), FERC also issued its *Order Nos. 679* and *679-A*, establishing incentive-based rate treatments to promote greater capital investment in electric utility infrastructure.

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[11] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 1991-1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, 1996-2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. N.Y. v. FERC,* 535 U.S. 1 (2002).

Q. HOW HAVE INVESTORS' RISK PERCEPTIONS FOR THE UTILITY INDUSTRY EVOLVED?

A. Implementation of these structural changes and related events have caused investors to rethink their assessment of the relative risks associated with the utility industry. The past decade witnessed steady erosion in credit quality throughout the electric power industry, both as a result of revised perceptions of the risks in the industry and the weakened finances of industry participants themselves. In December 2009, S&P observed with respect to the industry's future that:

> Looming costs associated with environmental compliance, slack demand caused by economic weakness, the potential for permanent demand destruction caused by changes in consumer behavior and closing of manufacturing facilities, and numerous regulatory filings seeking recovery of costs are some of the significant challenges the industry has to deal with.[12]

Q. WHAT PRINCIPAL FACTORS ARE CONSIDERED BY INVESTORS IN ASSESSING RISKS IN THE ELECTRIC UTILITY INDUSTRY?

A. In recent years, utilities and their customers have had to contend with dramatic fluctuations in energy costs due to ongoing price volatility in the spot markets and investors recognize the prospect of further turmoil in energy markets. In times of extreme volatility, utilities can quickly find themselves in a significant under-recovery position with respect to power costs, which can severely stress liquidity.[13] While expectations for significantly lower power prices reflect weaker fundamentals affecting current load and fuel prices, investors recognize the

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[12] Standard & Poor's Corporation, "U.S. Regulated Electric Utilities Head Into 2010 With Familiar Concerns," *RatingsDirect* (Dec. 28, 2009).

[13] This is also the case for utilities that serve as providers of last resort, which face significant working capital requirements to support electric commodity and transmission services provided under the mandate of standard offer services.

potential that such trends could quickly reverse. Moody's concluded that utilities remain exposed to "volatile commodity prices … which can wreak havoc on even the strongest utility liquidity profiles."[14]

Investors are also aware of the financial and regulatory pressures faced by utilities associated with both rising costs and the need to undertake significant capital investments. As Moody's observed:

> Utilities remain exposed to large, long-term capital investment challenges, volatile commodity prices and legal judgments that can wreak havoc on even the strongest liquidity profiles.[15]

Similarly, S&P recently noted that cost increases and capital projects, along with uncertain load growth, were a significant challenge to the utility industry.[16] Fitch reached similar conclusions:

> The combination of high capital expenditures and relatively weak electricity demand will continue to pressure credit quality and require base rate increases in 2010 and beyond.[17]

As noted earlier, the NPT Line will entail significant challenges and complexities in such a large-scale expansion of the transmission infrastructure. While enhancing the infrastructure necessary to meet economic, environmental, and reliability goals is certainly desirable, the magnitude of the associated capital

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[14] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).
[15] *Id.*
[16] Standard & Poor's Corporation, "Industry Economic And Ratings Outlook," *RatingsDirect* (Feb. 2, 2010).
[17] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

expenditures imposes additional financial responsibilities on Northern Pass that are heightened during times of capital market turmoil.

Investors also recognize that utilities are confronting increased environmental pressures that could impose significant uncertainties and costs. Moody's noted that "the prospect for new environmental emission legislation – particularly concerning carbon dioxide – represents the biggest emerging issue for electric utilities."[18] While the momentum for carbon emissions legislation has slowed, expectations for eventual regulations continue to pose uncertainty.

Q. HAVE INVESTORS RECOGNIZED THAT ELECTRIC UTILITIES FACE ADDITIONAL RISKS BECAUSE OF THE IMPACT OF INDUSTRY RESTRUCTURING ON TRANSMISSION OPERATIONS?

A. Yes. Transmission operations have become increasingly complex, and investors have recognized that difficulties in obtaining permits and uncertainty over the adequacy of allowed rates of return have contributed to heightened risk and fueled concerns regarding the adequacy of investment in the transmission sector of the electric power industry. At the same time, the development of competitive regional wholesale power markets has resulted in increased demand for transmission resources.

Q. CAN YOU DESCRIBE MORE FULLY THE REGULATORY RISKS THAT INVESTORS ASSOCIATE WITH TRANSMISSION OPERATIONS?

A. Yes. First, investors understand that there is always the potential that regulators will prevent the recovery of a utility's full costs, whether these are incurred

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[18] Moody's Investors Service, "U.S. Investor-Owned Electric Utilities," *Industry Outlook* (Jan. 2009).

through direct investment in transmission assets or through purchased power contracts. They remember disallowances by regulators through after-the-fact reviews in connection with the construction of generating projects in the 1980s and 1990s, as well as contentious disputes over the recovery of purchased power costs under contracts with Hydro-Quebéc.[19] There is no evidence that this exposure ended with restructuring, and investors have no reason to believe that regulators and intervenors will be less vigorous in pursuing potential disallowances than they have been in the past.

S&P concluded, "Any potential for after-the-fact prudence reviews and cost disallowances would stop transmission investment in its tracks by raising risks past the balance with the returns offered by such investments."[20] Similarly, investors also recognize that any future regulatory actions adversely impacting the economics of power delivered over the NPT Line could have negative implications for Northern Pass.

Second, investors in transmission take into account the possibility that long-lived transmission assets may become obsolete because of technological change or competition from alternatives. For example, if distributed generation or retail solar photovoltaic systems were to become a major new source of supply, it may reduce the need for existing transmission assets. Similarly, because the NPT

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[19] For example, in 2002 a witness for the Vermont Department of Public Service recommended that "the Board should disallow all of the above market costs of the Contract as imprudently incurred … if the Board finds that less than all of the above market costs of the Contract were imprudent, the Board should disallow entirely the portion of those above market costs found to be imprudent. The Board should then disallow a portion of the remaining portion of the above market costs as not used and useful." *Prefiled Testimony of William Steinhurst,* Docket No. 6956, State of Vermont Public Service Board (Mar. 7, 2002).

[20] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2007).

Line is being constructed for the primary purpose of importing low-carbon hydro-electric power from Québec, Northern Pass is exposed to changed circumstances that could potentially undermine the economics of the single-purpose project. Thus, investors perceive a long-term risk in the potential for stranded costs associated with transmission.

Third, investors recognize that operating a capital intensive business under the uncertainties created by multiple jurisdictions means higher risk – a consideration that is not lost on potential investors. In the case of Northern Pass, this risk is heightened because of the international nature of the NPT Line and the fact that the Company's sole customer is an affiliate of a Canadian crown corporation, and governed by Canadian laws.

Finally, investors recognize that utilities incur substantial up front costs to design transmission projects and then obtain siting approvals for them, and that regulators or customer groups may try to deny recovery of the associated costs if the projects are unable to obtain the required approvals. The investment community understands that regulation can lead to a significant lag between the time an investment is made and when the costs are recovered from customers and these up front capital costs may be tied up without earning an actual return for several years before the outcome of siting issues are decided. Messrs. Auseré, Lubbock, and Muntz discuss the implications of siting and project delays on Northern Pass in greater detail.

Q. IS THERE EVIDENCE THAT THESE UNCERTAINTIES CAN IMPACT INVESTORS' WILLINGNESS TO SUPPLY CAPITAL?

A. Yes. As early as 2003, the *Wall Street Journal* cited the debilitating impact of an "unsteady regulatory environment" and the "chaotic combination of regulated and

deregulated markets," in explaining inhibitions to increased investment in the electric utility system.[21] Similarly, S&P recognized continued concerns over the need to overcome obstacles to investment in transmission infrastructure and provide clarity in the regulatory framework:

> Like motherhood and apple pie, everybody favors pouring dollars into the transmission grid to improve reliability and provide a stronger platform for developing the wholesale electricity market, but there is considerably less consensus around how to encourage that investment (or [at] least not discourage it) and how to provide reasonable certainty concerning recovery.[22]

Even when capital is available, transmission facilities must compete with alternative uses and the additional funding necessary to meet the Commission's policy goals will only be allocated if investors anticipate an opportunity to earn a return that is sufficient to compensate for the associated risks.

Q. HAS FERC RECOGNIZED THE NEED FOR NEW INCENTIVES FOR INVESTMENT IN TRANSMISSION INFRASTRUCTURE?

A. Yes. To address the requirements of Section 219 of EPAct 2005, *Order Nos. 679* and *679-A* establish incentive-based rate treatments to achieve greater grid reliability and lower-cost electric power for customers by encouraging increased infrastructure investment. The Commission's rulings recognize the legislative mandate to promote capital investment in light of the substantial challenges faced by utilities in constructing new transmission projects. In response to this mandate, FERC provides utilities with the opportunity to seek various incentive rate treatments.

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[21] Smith, Rebecca, "Overloaded Circuits: Blackout Signals Major Weakness in U.S. Power Grid," *The Wall Street Journal* (Aug. 18, 2003).

[22] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2006).

Q. WHAT INCENTIVES DID THE COMMISSION ESTABLISH?

A. *Order Nos. 679 and 679-A* affirmed the Commission's policy of authorizing incentive-based rate treatment for utilities that join and/or continue to be a member of an RTO or other Commission-approved Transmission Organization. FERC concluded that providing incentives to each utility that joins a Transmission Organization is consistent with the mandate under the EPAct to ensure reliability and reduce the cost of delivered power:

> We consider an inducement for utilities to join, and remain in, Transmission Organizations to be entirely consistent with those purposes. The consumer benefits, including reliability and cost benefits, provided by Transmission Organizations are well documented, and the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities of Transmission Organizations and is effective for the entire duration of a utility's membership in the Transmission Organization.[23]

In addition to authorizing incentives for utilities that participate in RTOs, such as ISO-NE, the Commission also established a number of incentives intended to directly encourage construction of new transmission infrastructure. These include an incentive-based ROE for investments in new transmission facilities, the ability to include 100 percent of transmission-related Construction Work in Progress ("CWIP") in rates, potential recovery of pre-commercial and pre-construction costs and abandoned plant costs when abandonment of the project is beyond the utility's control, as well as the possibility of employing a hypothetical capital structure and accelerated depreciation.

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[23] *Order No. 679-A* at P 86 (footnotes omitted).

C. Impact of Capital Market Conditions

Q. WHAT ARE THE IMPLICATIONS OF RECENT CAPITAL MARKET CONDITIONS?

A. The deep financial and real estate crisis that the country experienced in late 2008, and continuing into 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase. While conditions improved significantly since the depths of the crisis, investors have had to confront ongoing fluctuations in share prices and stress in the credit markets. As the Wall Street Journal noted in February 2010:

> Stocks pulled out of a 167-point hole with a late rally Friday, capping a wild week reminiscent of the most volatile days of the credit crisis. … It was a return to the unusual relationships, or correlations, seen at major flash points over the past two years when investors fled risky assets and jumped into safe havens. This market behavior, which has reasserted itself repeatedly since the financial crisis began, suggests that investment decisions are still being driven more by government support and liquidity concerns than market fundamentals.[24]

In response to renewed capital market uncertainties initiated by concerns over the European sovereign debt crisis and the sustainability of economic growth, investors once again fled to the safety of U.S. Treasury bonds, and stock prices have experienced renewed volatility. Investors' risk premiums have widened, as evidenced by rising spreads between the yields on U.S. Treasuries compared to corporate bonds, and the dramatic rise in the price of gold and other commodities also attests to investors' heightened concerns over prospective

[24] Gongloff, Mark, "Stock Rebound Is a Crisis Flashback – Late Surge Recalls Market's Volatility at Peak of Credit Difficulties; Unusual Correlations," *Wall Street Journal* at B1 (Feb. 6, 2010).

challenges and risks, including the overhanging threat of inflation and renewed economic turmoil.

With respect to utilities specifically, as of September 2010, the Dow Jones Utility Average stock index remained approximately 25 percent below the previous high reached in May 2008. This sell-off in common stocks and sharp fluctuations in utility bond yields reflect the fact that the utility industry is not immune to the impact of financial market turmoil and the ongoing economic downturn. As the Edison Electric Institute ("EEI") noted in a letter to congressional representatives as the financial crisis intensified, capital market uncertainties have serious implications for utilities and their customers:

> In the wake of the continuing upheaval on Wall Street, capital markets are all but immobilized, and short-term borrowing costs to utilities have already increased substantially. If the financial crisis is not resolved quickly, financial pressures on utilities will intensify sharply, resulting in higher costs to our customers and, ultimately, could compromise service reliability.[25]

Similarly, an October 1, 2008 *Wall Street Journal* report confirmed that utilities had been forced to delay borrowing or pursue more costly alternatives to raise funds.[26] In December 2008, Fitch confirmed "sharp repricing of and aversion to risk in the investment community," and noted that the disruptions in financial markets and the fundamental shift in investors' risk perceptions had increased the cost of capital for utilities.[27]

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[25] *Letter to House of Representatives*, Thomas R. Kuhn, President, Edison Electric Institute (Sep. 24, 2008).
[26] Smith, Rebecca, "Corporate News: Utilities' Plans Hit by Credit Markets," *Wall Street Journal* at B4 (Oct. 1, 2008).
[27] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2009 Outlook," *Global Power North America Special Report* (Dec. 22. 2008).

In assessing the impact of the downturn on the utility sector, Fitch concluded, "While utilities maintained relatively good market access during the credit crisis, the cost of capital is higher than prior to the credit crisis, and bank credit remains relatively tight."[28] Similarly, S&P noted that while utilities are expected to maintain access to credit, such access will be "on more demanding terms than in previous years,"[29] with Moody's noting that "costs associated with credit facilities have increased significantly."[30]

Q. HOW DO INTEREST RATES ON LONG-TERM BONDS COMPARE WITH THOSE PROJECTED FOR THE NEXT FEW YEARS?

A. Table WEA-1 below compares current interest rates on 30-year Treasury bonds, triple-A rated corporate bonds, and double-A rated utility bonds with near-term projections from the Value Line Investment Survey ("Value Line"), IHS Global Insight, and the Energy Information Administration ("EIA"), a statistical agency of the U.S. Department of Energy ("DOE"):

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[28] Fitch Ratings Ltd., "Electric Utility Capital Spending: The Show Will Go On," *Global Power U.S. and Canada Special Report* (Oct. 14, 2009).

[29] Standard & Poor's Corporation, "Ratings Roundup: Ratings Trend In Electric Utility Sector Turns More Negative In First Quarter Of 2010," *RatingsDirect* (Apr. 16, 2010).

[30] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

TABLE WEA-1
INTEREST RATE TRENDS

	2011	2012	2013	2014	2015	Current (a)
30-Yr. Treasury						
Value Line (b)	4.1%	4.7%	5.5%	5.8%	--	4.0%
IHS Global Insight (c)	3.5%	3.8%	5.0%	5.1%	6.0%	4.0%
AAA Corporate						
Value Line (b)	4.8%	5.6%	6.0%	6.5%	--	4.7%
IHS Global Insight (c)	4.3%	4.7%	6.0%	6.2%	6.8%	4.7%
S&P (d)	5.1%	6.0%	7.1%	--	--	4.7%
AA Utility						
IHS Global Insight (c)	4.6%	5.0%	6.2%	6.4%	7.2%	5.0%
EIA (e)	6.4%	6.5%	6.8%	7.2%	7.2%	5.0%

(a) Based on monthly average bond yields for the six-month period June - November 2010 reported at www.credittrends.moodys.com and http://www.federalreserve.gov/releases/h15/data.htm.
(b) The Value Line Investment Survey, Forecast for the U.S. Economy (Nov. 26, 2010).
(c) IHS Global Insight, *U.S. Economic Outlook* at 19 (September 2010).
(d) Standard & Poor's Corporation, "U.S. Economic Forecast: A Happier Holiday," RatingsDirect (Dec. 7, 2010)
(e) Energy Information Administration, Annual Energy Outlook 2010 (May 11, 2010) at Table 20.

As evidenced above, there is a clear consensus that the cost of permanent capital will be higher in the 2011-2015 timeframe than it is currently. As a result, current cost of capital estimates are likely to understate investors' requirements during construction of the NPT Line and beyond.

Q. WHAT DO THESE EVENTS IMPLY WITH RESPECT TO THE ROE FOR NORTHERN PASS?

A. No one knows the future of our complex global economy. We know that the financial crisis had been building for a long time, and few predicted that the economy would fall as rapidly as it has, or that corporate bond yields would fluctuate as dramatically as they did. While conditions in the economy and capital markets appear to have stabilized significantly since 2009, investors continue to react swiftly and negatively to any future signs of trouble in the financial system or economy. The fact remains that the electric utility industry requires significant new capital investment. In addition, there are increasing pressures for regional transmission projects and grid reinforcement to support the

development of renewable resources and promote market efficiency. Given the challenges inherent in the NPT Line, it would be unwise to ignore investors' increased sensitivity to risk and future capital market trends in evaluating a fair ROE in this case.

III. FERC DCF APPROACH

Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

A. In this section, I develop estimates of the cost of equity for proxy groups of electric utilities using the Commission's DCF approach. First, I address the concept of the cost of equity, along with the risk-return tradeoff principle fundamental to capital markets. Next, I describe the specific DCF analyses I conducted to estimate the current cost of equity for the proxy groups.

A. Cost of Equity Concept

Q. WHAT ROLE DOES THE RETURN ON COMMON EQUITY PLAY IN A UTILITY'S RATES?

A. The return on common equity is the cost of inducing and retaining investment in the utility's physical plant and assets. This investment is necessary to finance the asset base needed to provide utility service. Competition for investor funds is intense and investors are free to invest their funds wherever they choose. They will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks.

Q. WHAT FUNDAMENTAL ECONOMIC PRINCIPLE UNDERLIES THIS COST OF EQUITY CONCEPT?

A. The fundamental economic principle underlying the cost of equity concept is the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to

hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as

$$k_i = R_f + RP_i$$

where: R_f = risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset is a function of: (1) the yield on risk-free assets and (2) the asset's relative risk, with investors demanding correspondingly larger risk premiums for bearing greater risk.

Q. IS THERE EVIDENCE THAT THE RISK-RETURN TRADEOFF PRINCIPLE ACTUALLY OPERATES IN THE CAPITAL MARKETS?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities, which are considered free of default risk, and bonds of various rating categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

Q. DOES THE RISK-RETURN TRADEOFF OBSERVED WITH FIXED INCOME SECURITIES EXTEND TO COMMON STOCKS AND OTHER ASSETS?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. IS THIS RISK-RETURN TRADEOFF LIMITED TO DIFFERENCES BETWEEN FIRMS?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is, therefore, the least risky. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such as subordinated debentures. The last investors in line with respect to a claim on the utility's assets are common shareholders. They receive only the net revenues, if any, which remain after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. WHAT DOES THE ABOVE DISCUSSION IMPLY WITH RESPECT TO ESTIMATING THE COST OF EQUITY?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

B. Development and Selection of a Proxy Group

Q. HOW DID YOU IMPLEMENT THE DCF METHOD TO ESTIMATE THE COST OF COMMON EQUITY FOR NORTHERN PASS?

A. Application of the DCF model to estimate the cost of equity requires observable capital market data, such as stock prices. Even for a firm with publicly traded stock, however, the cost of equity can only be estimated. As a result, applying quantitative models using observable market data produces a result that inherently includes some degree of observation error. Thus, the accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk comparable. The results of the analysis for the sample of companies are relied upon to establish a range of reasonableness for the cost of equity applicable to the specific company at issue.

Q. WHAT SPECIFIC PROXY GROUPS DID YOU RELY ON FOR YOUR ANALYSES?

A. My DCF analyses focused on a national group of other utilities composed of those companies included by Value Line in its Electric Utilities Industry groups with: (1) S&P corporate credit ratings between "BBB-" and "BBB+"; (2) a Value Line Safety Rank of "2" or "3"; (3) a Value Line Financial Strength Rating of "B" to "B++"; and, (4) published data from Value Line and IBES.[31] I excluded three firms that otherwise would have been in the proxy group, but are not appropriate for inclusion because they are involved in a major merger or acquisition (Allegheny Energy, Inc., FirstEnergy Corp., and NU). Finally, I verified that Value Line, S&P, and Thomson Reuters classify all of the proxy companies predominantly as electric utilities.[32] As shown on page 1 of Exhibit No. NPT-602, these criteria resulted in a proxy group composed of 24 companies, which I refer to as the "National Proxy Group." Reference to a national group of risk-comparable utilities follows the same general approach approved in *SoCal Edison*, and is consistent with the Commission's more recent findings that geographic proximity is not necessarily a determining factor when evaluating comparable risks.[33]

Because the Commission has previously determined that geographic proximity can serve as a relevant factor in determining a proxy group for

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[31] Formerly I/B/E/S International, Inc., IBES growth rates are now compiled and published by Thomson Reuters.

[32] *See, e.g., Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 at P 77 (2008) ("*Tallgrass*"). Constellation Energy Group Inc. was eliminated from the National Proxy Group on this basis.

[33] "FERC Clarifies ROE Policy for Electric Transmission Projects," *Federal Energy Regulatory Commission News* (Nov. 18, 2010); *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 (2010) ("*PATH Rehearing Order*").

transmission facilities that will be operated within the scope of ISO-NE,[34] I also considered a reference group of transmission-owning utilities in adjacent RTOs, which I refer to as the "Regional Proxy Group". Consistent with the Commission's findings in *Bangor Hydro* and *VEPCo*, the Regional Proxy Group includes the transmission-owning members of ISO-NE, PJM Interconnection, LLC ("PJM"), and the New York Independent System Operator, Inc. ("NYISO") with publicly traded stock. I again excluded Allegheny Energy, Inc., FirstEnergy Corp., and NU because of announced mergers, and verified that all of the proxy companies are classified predominantly as electric utilities.[35] In addition, consistent with the Commission's findings in *Bangor Hydro*, UGI Corporation was also eliminated from the proxy group.[36]

Finally, I also examined the results of the Commission's DCF model after screening the Regional Proxy Group to eliminate utilities with corporate credit ratings outside a "comparable risk band", which the Commission has interpreted as one "notch" higher or lower than the corporate ratings of the utility at issue and within the investment grade ratings scale.[37] Application of the Commission's credit rating screen, which includes ratings both one notch below and one notch above the "BBB" rating targeted for Northern Pass, results in a group of six companies. I refer to these utilities as the "Ratings Screen Proxy Group."

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[34] *See, e.g., Bangor Hydro* at P 3.; *Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 60 (2008) ("*VEPCo*").
[35] Constellation Energy Group Inc. was eliminated from the Regional Proxy Group on this basis.
[36] *Bangor Hydro* at P 37.
[37] *See, e.g.*, *Tallgrass* at P 77.

Q. WHAT RISK MEASURES DID YOU CONSIDER IN EVALUATING YOUR PROXY GROUPS?

A. My evaluation included a comparison of four objective measures of the investment risks associated with bonds and common stocks – S&P's corporate credit rating and Value Line's Safety Rank, Financial Strength Rating, and beta.

Credit ratings are assigned by independent rating agencies to provide investors with a broad assessment of the creditworthiness of a firm. Because the rating agencies' evaluation includes virtually all of the factors normally considered important in assessing a firm's relative credit standing, corporate credit ratings provide a broad measure of overall investment risk that is readily available to investors. Widely cited in the investment community and referenced by investors as an objective measure of risk, credit ratings are also frequently used as a primary risk indicator in establishing proxy groups to estimate the cost of equity. The Commission recently determined that "corporate credit ratings are a reasonable measure to use to screen for investment risk," and concluded, "Credit ratings are a key consideration in developing a proxy group that is risk-comparable."[38]

Apart from the broad assessment of investment risk provided by credit ratings, other quality rankings published by investment advisory services also provide relative assessments of risk that are considered by investors in forming their expectations. Given that Value Line is perhaps the most widely available source of investment advisory information, its rankings provide useful guidance regarding the risk perceptions of investors. The Safety Rank is Value Line's

[38] *PATH Rehearing Order* at P 63.

primary risk indicator and ranges from "1" (Safest) to "5" (Most Risky). This overall risk measure is intended to capture the total risk of a stock, and incorporates elements of stock price stability and financial strength.[39] The Financial Strength Rating is designed as a guide to overall financial strength and creditworthiness, with the key inputs including financial leverage, business volatility measures, and company size. Value Line's Financial Strength Ratings range from "A++" (strongest) down to "C" (weakest) in nine steps. Finally, Value Line's beta, which measures the volatility of a security's price relative to the market as a whole. A stock that tends to respond less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00.

Q. DO THESE CRITERIA PROVIDE OBJECTIVE EVIDENCE THAT INVESTORS WOULD VIEW THE PROXY GROUPS AS RISK-COMPARABLE?

A. Yes. Risk measures for the National Proxy Group and the two groups of regional utilities are shown on Exhibit No. NPT-602, and summarized in Table WEA-2, below:

[39] The Commission has previously considered Value Line's Safety Rank in evaluating relative risks. *PATH Rehearing Order* at n. 90.

TABLE WEA-2
COMPARATIVE RISK INDICATORS

	S&P	Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
National	BBB	3	B+	0.74
Regional	BBB+	2	B++	0.73
Ratings Screen	BBB	2	B++	0.76

While Northern Pass does not currently have a corporate credit rating, the proxy group averages are indicative of a utility with a rating in the triple-B category of the investment grade scale. This is also consistent with Moody's expectation that completion of the merger between NU and NSTAR will result in an overall rating "within the Baa rating category,"[40] as well as the target credit rating for Northern Pass.

Based on these criteria, which reflect objective, published indicators that incorporate consideration of a broad spectrum of risks, including financial and business position, relative size, and exposure to company specific factors, investors are likely to regard the National Proxy Group as having comparable risks and prospects that are indicative of those for Northern Pass. Taken together, these objective measures support the use of the National Proxy Group, as well as reference to the two groups of regional utilities, as the basis for estimating the ROE range of reasonableness for Northern Pass.

[40] Moody's Investors Service, "Announcement: Moody's affirms ratings of Northeast Utilities and NSTAR following merger," *Global Credit Research* (Oct. 18, 2010).

Q. WHAT OTHER CONSIDERATIONS SUPPORT THE USE OF THE NATIONAL PROXY GROUP IN EVALUATING THE ROE FOR NORTHERN PASS?

A. Estimating the cost of equity using any method is a stochastic process and the potential for misleading findings increases as the proxy group is narrowed. Developing a broad-based proxy group of comparable-risk electric utilities insulates against unreliable results. The cost of equity is inherently unobservable and can only be inferred indirectly by reference to available capital market data. Any form of analysis that depends on estimates, such as the growth parameter of the DCF model, is subject to measurement error. This potential for error is magnified when the analysis is restricted to a single method, such as the DCF.[41] To the extent that the data used to apply the DCF model does not capture the expectations that investors have incorporated into current stock prices, the resulting cost of equity estimates will be biased and unreliable.

Although the Commission has on occasion accepted proxy groups as small as four companies, FERC has generally recognized that a constrained proxy group "may not be representative of industry conditions."[42] The National Proxy Group addresses the problems associated with a limited sample by providing a greater number of data points for the comparable-risk utilities, which will provide a large enough sample that the Commission can be assured that it is representative of

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[41] In contrast to FERC's practice of focusing on DCF results, regulators have customarily considered alternative approaches in determining allowed returns, which can increase confidence that range of reasonableness is reliable and does not include implied costs of equity that are the result of spurious observations included in the data.

[42] *Enbridge Pipelines (KPC)*, 100 FERC ¶ 61,260 at P 237 (2002) (citing *Transcontinental Gas Pipe Line Corp*., 60 FERC ¶ 63,001, at 65,041 , *aff'd in part*, *rev'd in part*, 60 FERC ¶ 61,246, at 61,826 (1992), *rev'd and remanded*, *North Carolina Utilities v. FERC*, 42 F.3d 659 (1994), Order on Rehearing, *Transco,* 71 FERC ¶ 61,305, at 62,195 (1995)).

industry conditions and investor expectations and requirements for Northern Pass. The Company will compete with utilities throughout the country for the same limited pool of capital in order to finance infrastructure investment. Northern Pass should be permitted to offer comparable returns to potential investors of equity capital as are available elsewhere in the country.

C. DCF Model

Q. HOW IS THE DCF MODEL USED TO ESTIMATE THE COST OF EQUITY?

A. DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The model rests on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expectations, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. Thus, the cash flows that investors expect from a stock are estimated, and given the stock's current market price, we can back into the discount rate, or cost of equity, that investors implicitly used in bidding the stock to that price.

Q. WHAT MARKET VALUATION PROCESS UNDERLIES DCF MODELS?

A. DCF models assume that the price of a share of common stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return. Thus, the cost of equity is the discount rate that equates the current price

of a share of stock with the present value of all expected cash flows from the stock.

Q. WHAT FORM OF THE DCF MODEL IS CUSTOMARILY USED TO ESTIMATE THE COST OF EQUITY IN RATE CASES?

A. Rather than developing annual estimates of cash flows into perpetuity, after making certain assumptions, the DCF model can be simplified to a "constant growth" form:

$$P_0 = \frac{D_1}{k_e - g}$$

where: P_0 = Current price per share;
D_1 = Expected dividend per share in the coming year;
k_e = Cost of equity;
g = Investors' long-term growth expectations.

The cost of equity (k_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0} + g$$

This constant growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: 1) dividend yield (D_1/P_0); and 2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. HOW DID YOU CALCULATE THE DIVIDEND YIELD COMPONENT OF THE DCF MODEL?

A. Following Commission policy, average low and high indicated dividend yields were calculated for each electric utility during the six months June through November 2010. As indicated on Exhibit No. NPT-603, these six-month average low and high historical dividend yields were also increased by one-half of the low

and high growth rates discussed subsequently (1 + 0.5*g*) to convert them to adjusted dividend yields.

Q. WHAT GROWTH RATES ARE USED IN THE COMMISSION'S ONE-STEP DCF METHOD FOR ELECTRIC UTILITIES?

A. The one-step DCF method for electric utilities adopted by the Commission employs two growth rates for each firm. The first growth rate is a "sustainable" growth rate calculated by the following formula:

$$g = br + sv$$

where:
b = expected retention ratio;
r = expected earned rate of return;
s = percent of common equity expected to be issued annually as new common stock;
v = equity accretion ratio.

The second growth rate is the IBES consensus 5-year earnings growth forecast. These two growth rates are combined with the adjusted dividend yields to develop a cost of equity range for each company.

Q. HOW DID YOU CALCULATE THE SUSTAINABLE GROWTH RATE?

A. For each electric utility, the expected retention ratio (b) was calculated based on projected dividends and earnings per share from Value Line for 2010, 2011, and their 2013-2015 forecast horizon. Consistent with the Commission's DCF method, each firm's expected earned rate of return (r) was based on Value Line's end-of-year forecasts.[43] In *Southern California Edison*, the Commission correctly recognized that if the rate of return, or "r" component of the br+sv growth rate, is based on end-of-year book values, such as those reported by Value Line, it will

[43] *Bangor Hydro-Elec.Co.*, 122 FERC ¶ 61,265 at P 19 (2008).

understate actual returns because of growth in common equity over the year.[44] Accordingly, consistent with the Commission's findings and the theory underlying this approach to estimating investors' growth expectations, an adjustment was incorporated to compute an average rate of return.[45] Finally, the percent of common equity expected to be issued annually as new common stock (s) was equal to the product of the projected market-to-book ratio and growth in common shares outstanding over Value Line's forecast horizon, while the equity accretion rate (v) was computed as 1 minus the inverse of the projected market-to-book ratio. The calculation of the sustainable growth rate for each electric utility in the National and Regional Proxy Groups is shown on Exhibit Nos. NPT-604 and NPT-606.

Q. WHAT ARE INVESTMENT ANALYSTS' PROJECTED GROWTH RATES FOR THE PROXY COMPANIES?

A. The five-year IBES earnings growth forecasts for each electric utility in the proxy groups are shown in column (d) on Exhibit Nos. NPT-603 and NPT-605.

Q. WHAT WERE THE RESULTS OF APPLYING THE COMMISSION'S ONE-STEP DCF APPROACH TO THE PROXY GROUPS?

A. As shown on Exhibit No. NPT-603, application of the Commission's DCF model to the National Proxy Group resulted in current cost of equity estimates ranging from 1.5 percent to 19.1 percent. With respect to the Regional Proxy Group, as presented on Exhibit No. NPT-605, the results of the Commission's DCF model

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[44] *Southern California Edison* at 61,263 and n. 38.

[45] Use of an average return in developing the sustainable growth rate is well supported. *See, e.g.*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* (2006) at 305-306, which discusses the need to adjust Value Line's end-of-year data, consistent with the Commission's findings in *Southern California Edison*. The Commission affirmed the need for this adjustment to "r" in *Bangor Hydro-Elec. Co.*, 122 FERC ¶ 61,265 (2008).

ranged from 2.4 percent to 20.5 percent. Finally, DCF cost of equity estimates for the Ratings Screen Proxy Group (Exhibit No. NPT-607) ranged from 2.4 percent to 16.4 percent.

D. Evaluation of DCF Results

Q. IN EVALUATING THE RESULTS OF THE CONSTANT GROWTH DCF MODEL, IS IT APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT ARE EXTREME OUTLIERS?

A. Yes. In applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method.

Q. HOW DID YOU EVALUATE DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. It is a basic economic principle that investors can be induced to hold more risky assets only if they expect to earn a return to compensate them for the risk they assume. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by senior, long-term debt. Consistent with this principle, the DCF range must be adjusted to eliminate cost of equity estimates that are determined to be extreme low outliers when compared against the yields available to investors from less risky utility bonds.

Q. HAS THE COMMISSION RECOGNIZED THAT IT IS APPROPRIATE TO ELIMINATE COST OF EQUITY ESTIMATES THAT FAIL TO MEET THRESHOLD TESTS OF ECONOMIC LOGIC?

A. Yes. In *Southern California Edison,* the Commission noted that adjustments to the zone of reasonableness are justified where applications of its preferred DCF approach produce illogical results:

> An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. Because investors cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low-end return cannot be considered reliable in this case.[46]

Similarly, in its October 2006 decision in *Kern River Gas Transmission Company*, the Commission noted that:

> [T]he 7.31 and 7.32 percent costs of equity for El Paso and Williams found by the ALJ are only 110 and 122 basis points above that average yield for public utility debt.[47]

The Commission upheld the opinion of Staff and the Administrative Law Judge that cost of equity estimates for these two proxy group companies "were too low to be credible."[48]

The practice of eliminating low-end outliers has been affirmed in numerous proceedings,[49] and in its February 2008 decision in *Atlantic Path 15*,

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[46] *Southern California Edison* at 61,266 (note omitted).
[47] *Kern River Gas Transmission Company*, 117 FERC ¶ 61,077 at P 140 and n. 227 (2006).
[48] *Id.*
[49] *See, e.g., Virginia Electric Power Co.*, 123 FERC ¶ 61,098 at P 64 (2008) ("*VEPCo*").

the Commission disregarded a low-end cost of equity estimate of 7.29 percent.[50] In its April 15, 2010 decision in *SoCal Edison*, FERC affirmed that, "it is reasonable to exclude any company whose low-end ROE fails to exceed the average bond yield by about 100 basis points or more."[51]

Q. WHAT IS THE APPROPRIATE BOND YIELD BENCHMARK TO EVALUATE LOW-END DCF RESULTS?

A. The average S&P corporate credit rating for the firms in the National and Ratings Screen Proxy Groups is "BBB", with the Regional Proxy Group being rated "BBB+". Companies rated "BBB-", "BBB", and "BBB+" are all considered part of the triple-B rating category, with Moody's monthly yields on triple-B utility bonds averaging approximately 5.8 percent over the six-month period ending November 2010.[52]

Q. WHAT ELSE SHOULD BE CONSIDERED IN EVALUATING DCF ESTIMATES AT THE LOW END OF THE RANGE?

A. As indicated earlier, while corporate bond yields have declined substantially as the worst of the financial crisis has abated, it is generally expected that long-term interest rates will rise as the recession ends and the economy returns to a more normal pattern of growth. As shown in Table WEA-3 below, forecasts of IHS Global Insight and the EIA imply an average triple-B bond yield of 6.32 percent for 2011, or 7.18 percent over the 5-year period 2011-2015:

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[50] *Atlantic Path 15* at P 20; *Prepared Direct Testimony of James M. Coyne*, *Atlantic Path 15, LLC*, Docket No. ER08-374 at Exhibit ATL-7.
[51] *SoCal Edison* at P 55.
[52] Moody's Investors Service, www.credittrends.com.

TABLE WEA-3
IMPLIED BBB BOND YIELD

	2011	2011-15
Projected AA Utility Yield		
IHS Global Insight (a)	4.55%	5.87%
EIA (b)	6.43%	6.82%
Average	5.49%	6.35%
BBB - AA Yield Spread (c)	0.83%	0.83%
Implied Triple-B Utility Yield	**6.32%**	**7.18%**

(a) IHS Global Insight, *U.S. Economic Outlook* at 19 (September 2010).
(b) Energy Information Administration, *Annual Energy Outlook 2010* at Table 20 (May 11, 2010).
(c) Based on monthly average bond yields for the six-month period June - November 2010.

The increase in debt yields anticipated by IHS Global Insight and EIA is also supported by the widely-referenced Blue Chip Financial Forecasts, which projects that yields on corporate bonds will climb on the order of 70 basis points through the first quarter of 2012.[53]

Q. WHAT DOES THIS TEST OF LOGIC IMPLY WITH RESPECT TO THE DCF RESULTS FOR PROXY GROUPS?

A. As shown on Exhibit No. NPT-603, eight low-end DCF estimates ranged from 1.5 percent to 7.5 percent. Four of these estimates were either below or only marginally above current utility bond yields, and a cost of equity estimate of 7.5 percent is not sufficiently higher than the expected yields on BBB utility bonds to be considered a credible estimate of investors' required return on equity capital. Similarly, three of the low-end DCF estimates shown on Exhibit Nos. NPT-605

[53] *Blue Chip Financial Forecasts*, Vol. 29, No. 10 (Oct. 1, 2010).

and NPT-607 for the Regional and Ratings Screen Proxy Groups fell in the range of 2.4 percent to 6.5 percent.

In light of the risk-return tradeoff principle and the tests applied by the Commission in prior decisions, it is inconceivable that investors are not requiring a substantially higher rate of return for holding common stock, which is the riskiest of a utility's securities. As a result, consistent with the test of economic logic applied by FERC and the upward trend expected for utility bond yields, these values provide little guidance as to the returns investors require from utility common stocks and should be excluded.

Q. DO YOU ALSO RECOMMEND EXCLUDING COST OF EQUITY ESTIMATES AT THE HIGH END OF THE RANGE OF REASONABLENESS?

A. Yes. In a November 2004 Order in *Bangor Hydro*, the Commission determined that a cost of equity estimate at the high end of the range of reasonableness might also be excluded if it is determined to be an extreme outlier.[54] The Commission found that a 17.7 percent cost of equity estimate for PPL Corporation ("PPL") was "extreme" and that including this result would "skew the results."[55] The Commission also expressed concern regarding the sustainability of the underlying 13.3 percent growth estimate for PPL,[56] and has also referenced this threshold as a test of reasonableness.[57]

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[54] *ISO New England, Inc., et al*, 109 FERC ¶ 61,147 at P 205 (2004) ("*RTO Rehearing Order*").
[55] *Id.*
[56] *Id.*
[57] *See, e.g., SoCal Edison* at P 57.

As noted earlier, the upper end of the cost of equity range produced by the DCF analysis for the National Proxy Group presented in Exhibit No. NPT-603 was based on a cost of equity estimate of 19.1 percent for ITC Holdings Corp., with the high end estimate for Great Plains Energy being 18.0 percent. Accordingly, these high-end cost of equity estimates are clearly extreme outliers and are properly excluded under the rationale adopted by the Commission in *Bangor Hydro*, along with the 20.5 percent cost of equity estimate for the Regional Proxy Group shown on Exhibit No. NPT-605.

Q. WHAT ARE THE ADJUSTED ROE RANGES FOR THE PROXY GROUPS?

A. Eliminating the illogical low and high-end outliers shaded on Exhibit No. NPT-603 resulted in an adjusted range of reasonableness for the National Proxy Group ranging from 7.7 percent to 16.4 percent, which is identical to results for the Regional Proxy Group (Exhibit No. NPT-605). As shown on Exhibit No. NPT-607, eliminating outliers resulted in an adjusted range of reasonableness for the Ratings Screen Proxy Group of 8.6 percent to 16.4 percent.[58]

E. Evaluating an ROE Point Estimate

Q. IS IT NECESSARY TO DETERMINE A SINGLE POINT-ESTIMATE FROM WITHIN THE RANGE OF RESONABLENESS TO EVALUATE THE ROE SPECIFIED FOR NORTHERN PASS IN THE TSA?

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[58] I do not believe that it is necessary or appropriate to remove a company from the proxy group altogether when just one of its DCF values fails the test of logic. The fact that one growth rate estimate may produce a cost of equity that fails tests of economic logic says nothing about the veracity of the second, independent value. Nevertheless, excluding companies with illogical DCF estimates would have no effect on the adjusted range of reasonableness implied for the alternative proxy groups.

A. No. As detailed in the testimony of the Company's witnesses, there are significant financial commitments and risks associated with the NPT Line. Given these challenges, and the significant potential benefits to the regional grid, an incentive ROE would be warranted for Northern Pass. In *Order No. 679*, the Commission affirmed its practice of considering a range of returns in determining an appropriate ROE and eschewed the notion that a specific ROE adder was appropriate.[59] The Commission concluded that its rules provide for ROEs "at the upper end of the zone of reasonableness" for qualifying transmission investments, such as the NPT Line.[60] Thus, there is no need for the Commission to determine a single point-estimate, such as a midpoint or median, in order to evaluate the ROE specified under the TSA for Northern Pass.

Q. IF THE COMMISSION DETERMINES THAT A SINGLE POINT ESTIMATE IS REQUIRED, WHAT HAS BEEN FERC'S PAST POLICY?

A. Historically, the Commission was consistent in using the midpoint of the zone of reasonableness as the basis for allowed ROEs for electric utilities, as evidenced by *Bangor Hydro, Midwest ISO, Southern California Edison,* and in a plethora of other previous electric cases. For example, in *Consumers Energy*, the Commission reversed an initial decision in which the Presiding Judge had relied on the median of the zone of reasonableness, rather than the midpoint. The Commission concluded that:

> The precedent on which the judge and Staff rely in this instance was developed in the context of setting the rate of return for gas pipelines. In this case, there has been no reason provided to depart

[59] *Order No. 679* at P 93.
[60] *Id*.

> from our precedent in Opinion Nos. 445 and 446, setting the return at the midpoint of the zone of reasonableness.[61]

The Commission followed the same approach in *Consumers Energy* Co.[62] and *Utah Power & Light* Co.,[63] finding the midpoint to be the appropriate return for an electric utility. In certain decisions, however, the Commission has relied on the median rather than the midpoint.[64] More recently, FERC concluded, "in this *SoCal Edison* proceeding, for a single electric utility of average risk, the best measure of central tendency is the median."[65]

Q. WHAT RATIONALE DID THE COMMISSION ADVANCE TO SUPPORT ADOPTING THE MEDIAN?

A. The Commission determined that the median 1) "takes into account more of the companies in the proxy group", and 2) "minimizes the impact of a potentially skewed proxy group."[66]

Q. DO YOU AGREE THAT THE MEDIAN IS A SUPERIOR MEASURE OF CENTRAL TENDENCY WHEN EVALUATING THE ROE FOR A STAND-ALONE UTILITY?

A. No. I disagree with both of the findings underlying the Commission's decision to rely on the median DCF estimate when establishing the ROE for a single utility.

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[61] *Consumers Energy Co.*, 98 FERC ¶ 61,333, at 62,416 (2002).
[62] *Consumers Energy Co.*, 85 FERC ¶ 61,100 (1998).
[63] *Utah Power and Light Co.*, 44 FERC ¶ 61,166 (1988).
[64] *See, e.g.*, *VEPCO*, 123 FERC ¶ 61,098 (2008); *Golden Spread Elec. Cooperative, Inc., et al.*, 123 FERC ¶ 61,047 (2008) ("*Golden Spread*").
[65] *SoCal Edison* at P 92.
[66] *Id.* at P 87.

Q. DOES THE MEDIAN "TAKE INTO ACCOUNT MORE OF THE COMPANIES IN THE PROXY GROUP" THAN DOES THE MIDPOINT?

A. No. The median actually considers less information about the distribution of reasonable DCF results for the proxy group than does the midpoint. The median is simply the observation with an equal number of data values above and below. For odd-numbered samples, the median relies on only a **single number**, *e.g.*, the sixth number in an eleven-number set. If the number of estimates is an even number, then the median is the arithmetic average of the two numbers falling in the middle. Thus, if there were twelve estimates, then the median would in fact be the average of the sixth and seventh estimates arrayed from highest to lowest. As such, the median doesn't expressly "take into account" any information regarding the individual DCF estimates for the proxy companies that are above or below the single number (or average of two single numbers) that fall in the middle of the distribution.

While arguments against the midpoint frequently hinge on the contention that this value relies on only the top and bottom numbers in the range and ignores the rest, this argument is incorrect. As the D.C. Circuit has held, "[t]he midpoint doesn't 'completely disregard the middle three numbers'; the highest and lowest numbers achieve their status by reference to all five numbers."[67] Consider this example of a five-estimate sample to illustrate the point made by the D.C. Circuit. The estimates are 8.0, 8.1, 8.2, 15.0, and 15.1 percent. The median is 8.2 percent, while the range is 8.0 percent to 15.1 percent, with a midpoint of 11.55 percent. The median of 8.2 percent does not reflect the range of values nor does it include

[67] *Canadian Association of Petroleum Producers v. FERC*, 254 F.3d 289, 298 (D.C. Cir. 2001).

information about the 15.0 and 15.1 percent values that define the upper end of the range.

In fact, the median could be more readily criticized for under-weighting the results of the proxy group analysis, since it ignores the range of reasonable returns entirely. As the D.C. Circuit observed in approving the use of the midpoint for setting the ROE for the Midwest ISO:

> [P]etitioners [arguing in support of the median] are correct in noting that all measures of central tendency 'consider' the entire proxy group range, in the sense that all are influenced – at least indirectly – by each data point in the range. But only the midpoint *emphasizes* that range, as it is equally placed between the top and bottom values.[68]

The purpose of the Commission's DCF analysis is to produce a zone of reasonableness, and the midpoint provides a better representation of a single ROE applicable to this range than does the median, which ignores the boundaries of the range entirely.

Q. DO CONCERNS OVER SKEWED DCF RESULTS FAVOR THE MEDIAN OVER THE MIDPOINT?

A. No. Calculation of the median does not involve any examination of the reasonableness of individual cost of equity estimates; rather, it is simply a single number that divides a set of observed values in two equal halves, so that half of the values are below it, and half are above. Moreover, the Commission's DCF approach already establishes a framework to address concerns over skewed results by evaluating and excluding individual cost of equity estimates that are extreme

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[68] *Public Service Commission of the Commonwealth of Kentucky, v. FERC*, 397 F.3d 1004, 1010 (D.C. Cir. 2005).

outliers. In others words, eliminating illogical low and high-end DCF estimates when evaluating the results of the Commission's DCF approach also negates this second rationale advanced for reliance on the median.

Q. DOES IT MAKE SENSE TO DISTINGUISH BETWEEN FILINGS INVOLVING INDIVIDUAL COMPANIES AND THOSE INVOLVING GROUPS OF REGIONAL UTILITIES WHEN EVALUATING CENTRAL TENDENCY?

A. No. As noted above, the outcome of the Commission's DCF approach is a zone of reasonableness that reflects investors' required rate of return for a proxy group that is comparable in risk to the applicant, irrespective of whether the filing concerns a stand-alone utility or multiple members of a regional organization. In each case the object of the analysis is to obtain a reasonable and reliable range of the unobservable cost of equity based on objective estimates that contain unknown errors. Given the importance of the zone of reasonableness in framing the ROE under the Commission's precedent for electric utilities, the midpoint is more relevant in establishing a central point estimate that expressly considers this range.

Moreover, establishing different measures of central tendency based on whether the party is a single utility or a joint filing made up of multiple companies within a region creates the potential that different ROEs could be established for the same utility, solely depending on the nature of the filing. Such a perverse economic outcome has no logical relationship to changes in underlying capital market conditions or investors' risk perceptions or requirements, and it directly contradicts the Commission's well-articulated policy goals of reducing

regulatory impediments to investment in utility infrastructure and encouraging new capital investment.

Q. HOW ELSE MIGHT THE COMMISSION APPROACH THE DETERMINATION OF A SINGLE POINT ESTIMATE FROM WITHIN THE ROE RANGE?

A. The Commission has recognized that the determination of a reasonable point-estimate ROE ultimately should be governed by the facts specific to each proceeding, as the Commission explained in *Midwest ISO*:

> As an initial matter, we emphasize that the primary question to be considered here is not what constitutes the best overall method for determining ROE generically (i.e., the midpoint versus the median or mean); it is whether use of the midpoint is most appropriate in this case.[69]

The paramount consideration that must be reflected in the choice of a point estimate is the need to ensure that the end result meets the standards mandated by the Supreme Court to ensure that a utility can attract sufficient capital. This determination is not a quest to ordain a single statistical measure of central tendency. Rather, it challenges the Commission to consider the available evidence in this case and identify an ROE that is just, reasonable, and sufficient to support the Commission's goal of encouraging investment in wholesale utility infrastructure.

While I believe the midpoint provides a better representation of a single ROE applicable to the DCF zone of reasonableness, the Commission and other stakeholders might be better served by abandoning a policy of mechanistically

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[69] *Midwest Independent Transmission System Operator, Inc.*, 106 FERC ¶ 61,302 at P 8 (2004) ("*Rehearing Order*").

determining the point estimate based on a single statistical measure. The midpoint and median are both recognized statistical measures of central tendency and the Commission is free to weigh each of these values in its assessment of a fair ROE. As the Commission has recognized, "Each measure (median, average and midpoint) has advantages and drawbacks."[70] Considering the midpoint along with the median would be consistent with statistical principles, which favor retaining and evaluating all useful information in order to obtain the most reliable conclusion. Moreover, such a policy recognizes the inherent imprecision in estimating the cost of equity and the important role of informed judgment in evaluating the results of any quantitative analysis.

Q. WOULD THE COMMISSION INCREASE REGULATORY RISK BY ELECTING TO CONSIDER MORE THAN ONE STATISTICAL INDICATOR WHEN DETERMINING A FAIR ROE?

A. No. While the degree of regulatory support is clearly one of the most significant considerations for investors, they are far more concerned with the end-result and the implications for the utility's finances than with adherence to specific rules or precedent, no matter what the outcome. As S&P noted:

> As much as possible, regulators should, in our opinion, have the flexibility to react quickly and prudently to new situations as they develop. This is the sort of flexibility that we believe comes under principles-based regulation rather than rules-based regulation. In the latter, a regulator may attempt to set down every possible rule that can apply to a given situation that may arise in an industry. In the former, the regulator generally has the authority to achieve certain ends and some flexibility in how to achieve them.[71]

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[70] *Rehearing Order* at P 11.

[71] Standard & Poor's Corporation, "Executive Comment: What Characterizes Effective Regulation? Understanding, Manageability, And Consistency," *RatingsDirect* (May 5, 2010).

Similarly, a mechanical policy of referencing only the median of the DCF estimates leaves the Commission with little flexibility when the result fails to reflect a fair and reasonable ROE. In this instance, any benefit of consistency is more than overwhelmed by the risks that an unresponsive, mechanical policy will lead to inadequate returns. The Commission has previously recognized the key role of regulatory standards in evaluating a measure of central tendency, and has affirmed that the preeminent consideration in establishing an ROE is to ensure a reasonable end-result.[72]

Q. WHAT ARE THE MEASURES OF CENTRAL TENDENCY RESULTING FROM YOUR DCF ANALYSES?

A. The midpoint and median values indicated by my DCF analyses for the alternative proxy groups are summarized in Table WEA-4, below:[73]

TABLE WEA-4
SUMMARY OF DCF RESULTS

Proxy Group	Midpoint	Median
National	12.1%	10.4%
Regional	12.1%	10.2%
Ratings Screen	12.5%	11.2%
Non-Utility	12.8%	12.1%

[72] *Rehearing Order* at PP 13 & 14. The Commission observed that, "we are guided by the principle, enunciated by the Supreme Court, that an approved ROE should be 'reasonably sufficient to assure confidence in the financial soundness of the utility [or, in this case, utilities] and should be adequate under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.'" The Commission concluded, "we believe that the midpoint approach results in a ROE that is sufficient to assure confidence in the financial integrity of the member companies, so as to maintain credit and attract capital."

[73] My DCF analysis for the Non-Utility Proxy Group is explained subsequently.

As discussed earlier, I do not believe it is necessary to determine a single point estimate from within the ROE range; nor would I support or recommend sole reliance on the median to evaluate the ROE for Northern Pass. The table above demonstrates that the median values for the proxy groups of electric utilities produced using the Commission's methodology fall consistently below the midpoint. This downward bias, which is corroborated subsequently by the results of alternative methods, indicates that these median values are insufficient to meet the goal of ensuring Northern Pass's ability to maintain credit and attract capital.

F. Flotation Costs

Q. WHAT OTHER CONSIDERATIONS ARE RELEVANT IN EVALUATING THE ROE FOR A UTILITY?

A. The common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. These flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully

reflect all of the costs incurred for the use of investors' funds, with the need for a flotation cost adjustment having been documented in the financial literature.[74]

Q. WHAT IS THE MAGNITUDE OF THE ADJUSTMENT TO THE "BARE BONES" COST OF COMMON EQUITY TO ACCOUNT FOR ISSUANCE COSTS?

A. While there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. A review of the finance literature and other studies of issuance costs prepared by the investment community suggest an average flotation cost percentage in the range of 3.6 percent to 10 percent.[75] Applying these expense percentages to a representative dividend yield for a utility of 5.0 percent implies a flotation cost adjustment on the order of 18 to 50 basis points. While my DCF ranges do not include an adjustment for flotation costs, this is a legitimate consideration that supports the reasonableness of the ROE requested by Northern Pass in this case.

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[74] *See, e.g.*, Brigham, E.F., Aberwald, D.A., and Gapenski, L.C., "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly* (May, 2, 1985); Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006).

[75] *See, e.g.*, Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 323 (2006); *Application of Yankee Gas Services Company for a Rate Increase*, DPUC Docket No. 04-06-01, Direct Testimony of George J. Eckenroth (Jul. 2, 2004) at Exhibit GJE-11.1.

IV. ROE BENCHMARKS

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. I also evaluated the cost of equity for Northern Pass against ROE benchmarks developed 1) by applying the DCF model to a group of non-utility companies; 2) using the CAPM; and, 3) by reference to expected earned rates of return for utilities.

Q. WHAT EVIDENCE SUPPORTS YOUR REFERENCE TO ALTERNATIVE ROE BENCHMARKS?

A. I am well aware that the Commission has narrowed the focus of its ROE evaluation to a particular variant of the DCF approach. Nevertheless, because the cost of equity is unobservable, no single method should be viewed in isolation. Regulators have customarily considered the results of alternative approaches in determining allowed returns.[76] It is widely recognized that no single method can be regarded as a panacea; with all approaches having advantages and shortcomings. For example, a publication of the Society of Utility and Financial Analysts (formerly the National Society of Rate of Return Analysts), concluded that:

> Each model requires the exercise of judgment as to the reasonableness of the underlying assumptions of the methodology and on the reasonableness of the proxies used to validate the theory. Each model has its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental

[76] For example, a NARUC survey reported that 26 regulatory jurisdictions ascribe to no specific method for setting allowed ROEs, with the results of all approaches being considered. "Utility Regulatory Policy in the U.S. and Canada, 1995-1996," National Association of Regulatory Utility Commissioners (December 1996).

> premises, most of which cannot be validated empirically. Investors clearly do not subscribe to any singular method, nor does the stock price reflect the application of any one single method by investors.[77]

As the FCC recognized:

> Equity prices are established in highly volatile and uncertain capital markets... Different forecasting methodologies compete with each other for eminence, only to be superceded by other methodologies as conditions change... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[78]

Q. HAS THE COMMISSION ALSO RECOGNIZED THAT IT MAY BE APPROPRIATE TO CONSIDER THE RESULTS OF ALTERNATIVE METHODS?

A. Yes. For example, the Commission concluded in *Distrigas of Massachusetts Corp.* that, "no one methodology is preferred to the exclusion of all others. The DCF methodology, which we endorse, is but one analytical tool."[79] FERC has also granted that "[i]n some instances, the DCF methodology alone may be inappropriate."[80] While electing not to make "broadly applicable changes to how the Commission has traditionally performed its DCF analysis," *Order No. 679* noted the opinion that "there is a benefit to introducing more information into the

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[77] Parcell, David C., "The Cost of Capital – A Practitioner's Guide," *Society of Utility and Regulatory Financial Analysts* (1997) at Part 2, p. 4.

[78] Federal Communications Commission, Report and Order 42-43, CC Docket No. 92-133 (1995).

[79] *Distrigas of Massachusetts Corp.,* 41 FERC ¶ 61,205 at 61,550 (1987), *modified on reh'g,* 42 FERC ¶ 61,225 (1988).

[80] *Williston Basin Interstate Pipeline Co.,* 50 FERC ¶ 61,284 at 61,913 n.90 (1990), *vacated on other grounds,* 931 F.2d 949 (D.C. Cir. 1991).

analysis process," and FERC indicated a willingness to consider modification to its standard approach on a case-by-case basis.[81] More recently, in *SoCal Edison*, the Commission determined that additional methods could be used to test or corroborate the results of its preferred DCF approach.[82]

A. Non-Utility DCF Model

Q. WHAT OTHER PROXY GROUP DID YOU CONSIDER IN EVALUATING A FAIR ROE FOR NORTHERN PASS?

A. Consistent with underlying economic and regulatory standards, I also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. I refer to this group as the "Non-Utility Proxy Group".

Q. DO UTILITIES HAVE TO COMPETE WITH NON-REGULATED FIRMS FOR CAPITAL?

A. Yes. The cost of capital is an opportunity cost based on the returns that investors could realize by putting their money in other alternatives. Clearly the total capital invested in utility stocks is only the tip of the iceberg of total common stock investment, and there are a plethora of other enterprises available to investors beyond those in the utility industry. Utilities must compete for capital, not just against firms in their own industry, but with other investment opportunities of comparable risk. With regulation taking the place of competitive market forces, required returns for utilities should be in line with those of non-utility firms of comparable risk operating under the constraints of free competition.

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[81] *Order No. 679*, 116 FERC ¶ 61,057 at P 102 (2006); *Order No. 679-A*, 117 FERC ¶ 61,327 at P 63 (2006).
[82] *SoCal Edison* at P 116.

Q. IS IT CONSISTENT WITH THE *BLUEFIELD* AND *HOPE* CASES TO CONSIDER REQUIRED RETURNS FOR NON-UTILITY COMPANIES?

A. Yes. Returns in the competitive sector of the economy form the very underpinning for utility ROEs because regulation purports to serve as a substitute for the actions of competitive markets. The Supreme Court has recognized that it is the degree of risk, not the nature of the business, which is relevant in evaluating an allowed ROE for a utility. The *Bluefield* case refers to "business undertakings attended with comparable risks and uncertainties." It does not restrict consideration to other utilities. Indeed, if the requirement is business in the same part of the country and the utility has the exclusive franchise, then the Court could only be referring to non-utility businesses and any nearby utilities. Similarly, the *Hope* case states:

> By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

As in the *Bluefield* decision, there is nothing to restrict "other enterprises" solely to the utility industry.

Indeed, in teaching regulatory policy I usually observe that in the early applications of the comparable earnings approach, utilities were explicitly eliminated due to a concern about circularity. In other words, soon after the *Hope* decision regulatory commissions did not want to get involved in circular logic by looking to the returns of utilities that were established by the same or similar regulatory commissions in the same geographic region. To avoid circularity, regulators looked only to the returns of non-utility companies.

Q. DOES CONSIDERATION OF THE RESULTS FOR THE NON-UTILITY PROXY GROUP MAKE THE ESTIMATION OF THE COST OF EQUITY USING THE DCF MODEL MORE RELIABLE*?*

A. Yes. The estimates of growth from the DCF model depend on analysts' forecasts. It is possible for utility growth rates to be distorted by short-term trends in the industry or the industry falling into favor or disfavor by analysts. The result of such distortions would be to bias the DCF estimates for utilities. For example, Value Line recently observed that near-term growth rates understate the longer-term expectations for gas utilities:

> Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months. Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years.[83]

Because the Non-Utility Proxy Group includes low risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Q. WHAT CRITERIA DID YOU APPLY TO DEVELOP THE NON-UTILITY PROXY GROUP?

A. My comparable risk proxy group was composed of those U.S. companies followed by Value Line that: 1) pay common dividends; 2) have a Safety Rank of "1"; 3) have a Financial Strength Rating of "B++" or greater; 4) have a beta of 0.85 or less; and, 5) have investment grade credit ratings from S&P. While any

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[83] The Value Line Investment Survey at 445 (Mar. 12, 2010).

differences in investment risk attributable to regulation should already be reflected in these objective measures, my analyses nevertheless conservatively focus on a lower-risk group of non-utility firms.

Q. HOW DO THE OVERALL RISKS OF THIS NON-UTILITY PROXY GROUP COMPARE WITH NORTHERN PASS?

A. Table WEA-5 compares the Non-Utility Proxy Group with the Regional and National Proxy Groups across four key indicators of investment risk.

TABLE WEA-5
NON-UTILITY PROXY GROUP RISK INDICATORS

	S&P	Value Line		
Proxy Group	**Credit Rating**	**Safety Rank**	**Financial Strength**	**Beta**
Non-Utility	A	1	A+	0.71
National	BBB	3	B+	0.74
Regional	BBB+	2	B++	0.73
Ratings Screen	BBB	2	B++	0.76

As shown above, the average risk indicators for the Non-Utility Proxy Group suggest less risk than for the proxy groups of utilities. Thus, while the impact of differences in regulation is already reflected in objective risk measures, my analyses conservatively focus on a lower-risk group of non-utility firms. Considered together, a comparison of these objective measures, which consider a broad spectrum of risks, including financial and business position, relative size, and exposure to company-specific factors, indicates that investors would likely conclude that the overall investment risks for the National and Regional Proxy Groups – and Northern Pass – are greater than those of the firms in the Non-Utility Proxy Group.

My Non-Utility Proxy Group is comprised of 51 of the best-known and most stable corporations in America and has risk measures that are less than the proxy groups of electric utilities referenced in my analyses. While these companies do not have the regulatory protections that utilities have, neither do they bear the burdens of losing control over their prices, undertaking the obligation to serve, and having to invest in infrastructure even in unfavorable market conditions. Northern Pass can't relocate its facilities to an area with higher prospects for economic growth, postpone capital spending necessary to maintain reliability of the NPT Line, or abandon its customer when turmoil roils energy or capital markets.

Q. WHAT WERE THE RESULTS OF YOUR DCF ANALYSIS FOR THE NON-UTILITY PROXY GROUP?

A. The results of my DCF analysis for the Non-Utility Proxy Group are presented in Exhibit No. NPT-608, with the sustainable, br+sv growth rates being developed on Exhibit No. NPT-609. As shown there, after eliminating illogical low and high-end values, application of the constant growth DCF model resulted in an ROE range of reasonableness of 8.1 percent to 17.5 percent, with a midpoint of 12.8 percent. The median was 12.1 percent.

B. Capital Asset Pricing Model

Q. WHAT OTHER ANALYSES DID YOU CONDUCT TO ESTIMATE THE COST OF EQUITY?

A. I also evaluated the cost of equity for Northern Pass against an ROE benchmark developed using the CAPM. As noted above, the Commission has recognized that it may be appropriate to consider the results of alternative methods on a case-by-case basis, with the CAPM being the dominant model for estimating the cost of

equity outside the regulatory sphere.[84] In contrast to applications of the CAPM using historical, realized rates of return, which have been largely rejected by the Commission in the past, my CAPM analysis specifically incorporated forward-looking expectations that are consistent with the assumptions of this approach.

Q. PLEASE DESCRIBE THE CAPM.

A. The CAPM is generally considered to be the most widely referenced method for estimating the cost of equity among academicians and professional practitioners, with the pioneering researchers of this method receiving the Nobel Prize in 1990. The CAPM is a theory of market equilibrium that measures risk using the beta coefficient. The CAPM assumes that investors are fully diversified, so that the relevant risk of an individual asset (e.g., common stock) is its volatility relative to the market as a whole. Beta reflects the tendency of a stock's price to follow changes in the market. A stock that tends to respond relatively less to market movements has a beta less than 1.00, while stocks that tend to move more than the market have betas greater than 1.00. The CAPM is mathematically expressed as:

$$R_j = R_f + \beta_j(R_m - R_f)$$

where: Rj = required rate of return for stock j;
R_f = risk-free rate;
R_m = expected return on the market portfolio; and
β_j = beta, or systematic risk, for stock j.

Like the DCF model, the CAPM is an *ex-ante,* or forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using data that reflects the expectations of actual investors in the market.

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[84] *See*, *e.g.*, Bruner, R.F., Eades, K.M., Harris, R.S., and Higgins, R.C., "Best Practices in Estimating Cost of Capital: Survey and Synthesis," *Financial Practice and Education* (1998).

Q. HOW DID YOU APPLY THE CAPM TO ESTIMATE THE COST OF COMMON EQUITY?

A. Application of the CAPM based on a forward-looking estimate for investors' required rate of return from common stocks is presented on Exhibit No. NPT-610. In order to capture the expectations of today's investors in current capital markets, the expected market rate of return was estimated by conducting a DCF analysis on the dividend paying firms in the S&P 500.

The dividend yield for each firm was calculated based on the annual indicated dividend payment obtained from Value Line, increased by one-years' growth using the rate discussed subsequently $(1 + g)$ to convert them to year-ahead dividend yields presumed by the constant growth DCF model. The growth rate was equal to the consensus earnings growth projections for each firm published by IBES, with each firm's dividend yield and growth rate being weighted by its proportionate share of total market value. Based on the weighted average of the projections for the 354 individual firms, current estimates imply an average growth rate over the next five years of 10.6 percent. Combining this average growth rate with an adjusted dividend yield of 2.5 percent results in a current cost of common equity estimate for the market as a whole of approximately 13.1 percent. Subtracting a 4.0 percent risk-free rate based on the average yield on 30-year Treasury bonds over the six months ended November 2010 produced a market equity risk premium of 9.1 percent.

Q. WHAT WAS THE SOURCE OF THE BETA VALUES YOU USED TO APPLY THE CAPM?

A. I relied on the beta values reported by Value Line, which in my experience is the most widely referenced source for beta in regulatory proceedings. As noted in *New Regulatory Finance*:

> Value Line is the largest and most widely circulated independent investment advisory service, and influences the expectations of a large number of institutional and individual investors. … Value Line betas are computed on a theoretically sound basis using a broadly-based market index, and they are adjusted for the regression tendency of betas to converge to 1.00.[85]

Q. WHAT COST OF EQUITY ESTIMATES WERE INDICATED FOR THE ALTERNATIVE PROXY GROUPS BASED ON THIS FORWARD-LOOKING APPLICATION OF THE CAPM?

A. The results of the CAPM analyses presented in Exhibit No. NPT-610 are summarized in Table WEA-6, below:

TABLE WEA-6
SUMMARY OF CAPM RESULTS

Proxy Group	Midpoint	Median
National	10.5%	10.8%
Regional	10.6%	10.4%
Ratings Screen	11.1%	10.8%
Non-Utility	10.1%	10.8%

Taken together, these CAPM estimates suggest a cost of equity on the order of 10.6 percent.

[85] Morin, Roger A., "New Regulatory Finance," *Public Utilities Reports, Inc.* at 71 (2006).

Q. SHOULD THE CAPM APPROACH BE APPLIED USING HISTORICAL DATA?

A. No. The CAPM cost of common equity estimate is calibrated from investors' required risk premium between Treasury bonds and common stocks. In response to heightened uncertainties, investors have repeatedly sought a safe haven in U.S. government bonds and this "flight to safety" has pushed Treasury yields significantly lower while yield spreads for corporate debt have widened. This distortion not only impacts the absolute level of the CAPM cost of equity estimate, but it affects estimated risk premiums. Economic logic would suggest that investors' required risk premium for common stocks over Treasury bonds has also increased.

Meanwhile, backward-looking approaches incorrectly assume that investors' assessment of the required risk premium between Treasury bonds and common stocks is constant, and equal to some historical average. At no time in recent history has the fallacy of this assumption been demonstrated more concretely. This incongruity between investors' current expectations and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently.[86]

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[86] The Commission has previously rejected CAPM methodologies based on historical data because whatever historical relationships existed between debt and equity securities may no longer hold. *See Orange & Rockland Utils., Inc., 40 F.E.R.C. P63,053, at pp. 65,208 -09 (1987), aff'd, Opinion No. 314, 44 F.E.R.C. P61,253 at 65,208.*

C. Expected Earnings Approach

Q. WHAT OTHER BENCHMARKS DID YOU DEVELOP TO EVALUATE THE ROE FOR NORTHERN PASS?

A. As I noted earlier, I also evaluated the ROE by reference to expected rates of return for electric utilities. Reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. This approach is consistent with the economic underpinnings for a fair rate of return, as reflected in the comparable earnings test established by the Supreme Court in *Hope* and *Bluefield.* Moreover, it avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors.

Q. WHAT ECONOMIC PREMISE UNDERLIES THE EXPECTED EARNINGS APPROACH?

A. The simple, but powerful concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. For existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. In this situation the government is effectively taking the value of investors' capital without adequate compensation.

Q. HOW IS THE COMPARISON OF OPPORTUNITY COSTS TYPICALLY IMPLEMENTED?

A. The traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications (*e.g.*, Value Line). Because these expected returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison. My application of the expected earnings approach was focused exclusively on forward-looking projections, not historical data.

Moreover, regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. This opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

Q. WHAT RATES OF RETURN ON EQUITY ARE INDICATED FOR ELECTRIC UTILITIES BASED ON THE EXPECTED EARNINGS APPROACH?

A. Value Line reports that its analysts anticipate an average rate of return on common equity for the electric utility industry of 10.5 percent in 2011 and over its 2013-2015 forecast horizon.[87] Meanwhile, for the firms in the National Proxy Group specifically, the returns on common equity projected by Value Line over its forecast horizon are shown on page 1 of Exhibit No. AP-611. Consistent with the rationale underlying the development of the br+sv growth rates, these year-end values were converted to average returns using the same adjustment factor discussed earlier and developed on Exhibit No. NPT-604. As shown on page 1 of Exhibit No. AP-611, Value Line's projections for the National Proxy Group suggest an ROE midpoint of 11.6 percent after eliminating low and high-end outliers, with the median being 9.9 percent. For the Regional Proxy Group (page 2 of Exhibit NPT-611), Value Line's expected rates of return resulted in an ROE midpoint of 13.5 percent and a median of 12.9 percent, after excluding outliers. Expected rates of return for the Ratings Screen Proxy Group resulted in a midpoint of 13.7 percent and a median of 12.8 percent.

V. RETURN ON EQUITY RANGE FOR NORTHERN PASS

Q. WHAT IS THE PURPOSE OF THIS SECTION?

A. This section presents my conclusions regarding a fair ROE range of reasonableness for Northern Pass. It examines other factors properly considered

[87] The Value Line Investment Survey at 139 (Nov. 26, 2010).

in determining a fair rate of return, including the relationship between ROE and preservation of a utility's financial integrity and the ability to attract capital.

A. Implications for Financial Integrity

Q. WHY IS IT IMPORTANT TO ALLOW NORTHERN PASS AN ADEQUATE ROE?

A. Given the social and economic importance of the utility industry, it is essential to maintain reliable and economical service to all consumers. While Northern Pass remains committed to ensure that the benefits of the NPT Line are realized, a utility's ability to fulfill its mandate can be compromised if it lacks the necessary financial wherewithal or is unable to earn a return sufficient to attract sufficient capital.

As documented earlier, the major rating agencies have warned of exposure to uncertainties associated with political and regulatory developments, especially in view of current financial and operating pressures in the utility industry. Investors understand just how swiftly unforeseen circumstances can lead to deterioration in a utility's financial condition, and stakeholders have discovered first hand how difficult and complex it can be to remedy the situation after the fact. Investors' increased reticence to supply additional capital during times of crisis highlights the need to preserve financial flexibility and the importance of allowing an adequate ROE.

Q. WHAT ROLE DOES REGULATION PLAY IN ENSURING ACCESS TO CAPITAL FOR NORTHERN PASS?

A. Considering investors' heightened awareness of the risks associated with the utility industry and the damage that results when a utility's financial flexibility is compromised, supportive regulation remains crucial to the Company's access to

capital. Investors recognize that regulation has its own risks, and that constructive regulation is a key ingredient in supporting utility credit ratings and financial integrity, particularly during times of adverse conditions. Fitch concluded, "[G]iven the lingering rate of unemployment and voter concerns about the economy, there could well be pockets of adverse rate decisions, and those companies with little financial cushion could suffer adverse effects."[88] Moody's has also emphasized the need for regulatory support, concluding:

> For the longer term, however, we are becoming increasingly concerned about possible changes to our fundamental assumptions about regulatory risk, particularly the prospect of a more adversarial political (and therefore regulatory) environment. A prolonged recessionary climate with high unemployment, or an intense period of inflation, could make cost recovery more uncertain.[89]

S&P noted "the quality of regulation is at the forefront of our analysis of utility creditworthiness."[90]

Q. DO THE EXPOSURES UNIQUE TO THE NPT LINE HIGHLIGHT THE NEED FOR ONGOING SUPPORT OF NORTHERN PASS' FINANCIAL STRENGTH AND ABILITY TO ATTRACT CAPITAL?

A. Most definitely. As discussed earlier and in the testimony of the Company's other witnesses, Northern Pass faces numerous challenges associated with financing and constructing the NPT Line. The scope, complexity, and magnitude of the

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[88] Fitch Ratings Ltd., "U.S. Utilities, Power and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).
[89] Moody's Investors Service, "U.S. Regulated Electric Utilities, Six-Month Update," *Industry Outlook* (July 2009).
[90] Standard & Poor's Corporation, "Assessing U.S. Utility Regulatory Environments," *RatingsDirect* (Nov. 7, 2008).

investment required to support the NPT Line far exceeds what is customarily involved in more routine transmission additions. Given the potential for significant volatility in capital markets and the Company's lack of control over the timing of such events, it is crucial that Northern Pass receive adequate support for its credit standing.

The capital commitments necessary for the construction of the NPT Line, and subsequent financing for the in-service period, are predicated on the expectation that Northern Pass will have the opportunity to earn returns that are commensurate with the significant risks entailed in the project's development. Northern Pass faces the prospect of financing and constructing the NPT Line, which is its only principal asset. Investors recognize that there are considerable uncertainties associated with a single-asset project financing involving significant investment and complexities. Moreover, in contrast to established firms operating in the electric utility sector of the power industry, Northern Pass is essentially a start-up company that lacks any operating history, and its only asset is a single-purpose facility serving just one customer.

Q. DO CUSTOMERS BENEFIT BY ENHANCING THE UTILITY'S FINANCIAL FLEXIBILITY?

A. Yes. Providing an ROE that is sufficient to maintain Northern Pass's ability to attract capital, even under duress, is consistent with the economic requirements embodied in the Supreme Court's *Hope* and *Bluefield* decisions, but it is also in customers' best interests. Ultimately, it is customers and the service area economy that enjoy the benefits that come from ensuring that the utility has the financial wherewithal to take whatever actions are required to ensure a reliable energy supply. By the same token, customers also bear a significant burden when

the ability of the utility to attract capital is impaired and service quality is compromised.

B. Capital Structure

Q. IS AN EVALUATION OF THE CAPITAL STRUCTURE MAINTAINED BY A UTILITY RELEVANT IN ASSESSING ITS ROE?

A. Yes. Other things being equal, a higher debt ratio, or lower common equity ratio, translates into increased financial risk for all investors. A greater amount of debt means more investors have a senior claim on available cash flow, thereby reducing the certainty that each will receive his contractual payments. This increases the risks to which lenders are exposed, and they require correspondingly higher rates of interest. From common shareholders' standpoint, a higher debt ratio means that there are proportionately more investors ahead of them, thereby increasing the uncertainty as to the amount of cash flow, if any that will remain.

Q. WHAT COMMON EQUITY RATIO IS SPECIFIED FOR NORTHERN PASS?

A. The TSA specifies that Northern Pass will use commercially reasonable efforts to maintain a capital structure consisting of 50 percent common equity and 50 percent long-term debt, and will use these capitalization ratios to calculate transmission service payments under the formula rate.

Q. HOW DO THESE RATIOS COMPARE WITH COMMON EQUITY RATIOS MAINTAINED BY THE PROXY GROUPS?

A. As shown on page 1 of Exhibit No. NPT-612, common equity ratios for the individual firms in the National Proxy Group ranged from a low of 27.4 percent to a high of 52.7 percent at year-end 2009, with the average being 44.6 percent. Meanwhile, Value Line's three-to-five year forecast indicates an average common

equity ratio of 46.9 percent for the National Proxy Group, with the individual equity ratios ranging from 29.0 percent to 54.5 percent.

Comparable data for the Regional Proxy Group is shown on page 2 of Exhibit No. NPT-612. As shown there, the average common equity ratio for this group of electric utilities was 46.2 percent at year-end 2009, or 50.1 percent based on Value Line's forecast horizon. For the firms in the Ratings Screen Proxy Group (page 3 of Exhibit No. NPT-612), the average historical and projected common equity ratios were 47.5 percent and 50.7 percent, respectively.

Q. WHAT IMPLICATION DOES THE INCREASING RISK OF THE INDUSTRY HAVE FOR THE CAPITAL STRUCTURES MAINTAINED BY UTILITIES?

A. As discussed earlier, utilities are facing energy market volatility, rising cost structures, the need to finance significant capital investment plans, uncertainties over accommodating future environmental mandates, and ongoing regulatory risks. Coupled with the potential for turmoil in capital markets, these considerations warrant a stronger balance sheet to deal with an increasingly uncertain environment. A more conservative financial profile, in the form of a higher common equity ratio, is consistent with increasing uncertainties and the need to maintain the continuous access to capital that is required to fund operations and necessary system investment, even during times of adverse capital market conditions.

Moody's has repeatedly warned investors of the risks associated with debt leverage and fixed obligations and advised utilities not to squander the

opportunity to strengthen the balance sheet as a buffer against future uncertainties.[91] More recently, Moody's concluded:

> From a credit perspective, we believe a strong balance sheet coupled with abundant sources of liquidity represents one of the best defenses against business and operating risk and potential negative ratings actions.[92]

Similarly, S&P recently noted that, "we generally consider a debt to capital level of 50% or greater to be aggressive or highly leveraged for utilities."[93] Fitch affirmed that it expects regulated utilities "to extend their conservative balance sheet stance in 2010," and employ "a judicious mix of debt and equity to finance high levels of planned investments."[94]

Q. WHAT DOES THIS EVIDENCE SUGGEST WITH RESPECT TO THE CAPITAL STRUCTURE SPECIFIED IN THE TRANSMISSION SERVICE AGREEMENT?

A. Based on my evaluation, I concluded that a capital structure consisting of 50 percent common equity and 50 percent long-term debt represents a reasonable mix of capital sources from which to calculate an overall rate of return for Northern Pass. This capital structure is consistent with the range of capitalizations maintained by the firms in the alternative proxy groups, especially

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[91] Moody's Investors Service, "Storm Clouds Gathering on the Horizon for the North American Electric Utility Sector," *Special Comment* (Aug. 2007); "U.S. Electric Utility Sector," *Industry Outlook* (Jan. 2008).

[92] Moody's Investors Service, "U.S. Electric Utilities Face Challenges Beyond Near-Term," *Industry Outlook* (Jan. 2010).

[93] Standard & Poor's Corporation, "Ratings Roundup: U.S. Electric Utility Sector Maintained Strong Credit Quality In A Gloomy 2009," *RatingsDirect* (Jan. 26, 2010).

[94] Fitch Ratings Ltd., "U.S. Utilities, Power, and Gas 2010 Outlook," *Global Power North America Special Report* (Dec. 4, 2009).

when considering the trend towards lower financial leverage expected for the industry.

While industry averages provide one benchmark for comparison, the capitalization for Northern Pass should reflect the special risks and challenges inherent in constructing the NPT Line, as well as its specific needs to access the capital markets. Financial flexibility plays a crucial role in ensuring the wherewithal to meet the needs of customers, and utilities with higher leverage may be foreclosed from additional borrowing, especially during times of stress. The need for access becomes even more important when considering that the NPT Line will involve large capital requirements over a period of years and financing must be continuously available.

The Company's capital structure is consistent with industry benchmarks and reflects the fact that it is a start-up entity, as well as the financial realities necessary to achieve the benefits associated with the NPT Line. As the Commission has previously recognized, a capitalization consisting of 50 percent equity and 50 percent debt provides certainty and improves access to capital, as well as reflecting the somewhat fluid nature of the capital structure during construction.[95] Additionally, the Commission has also recognized that a 50 percent debt/50 percent equity capital structure is reasonable for a fledgling company that lacks an established capitalization.[96] The reasonableness of the proposed capital structure for Northern Pass reinforced by the ongoing uncertainties associated with the electric power industry, the need to

[95] *Tallgrass* at P 68.
[96] *Trans Bay Cable LLC,* 112 FERC ¶ 61,095 at P 27 (2005) ("*Trans Bay Cable*").

accommodate ongoing regulatory risks, and the importance of supporting continued system investment, even during times of adverse industry or market conditions.

C. Incentive for New Transmission Investment

Q. WHY IS IT IMPORTANT TO ALLOW AN INCENTIVE RETURN FOR NEW TRANSMISSION INVESTMENT, SUCH AS THE NPT LINE?

A. As documented in the testimony of the Company's witnesses, the NPT Line will provide significant economic benefits, while supporting environmental and public policy objectives, diversifying New England's power supply mix, and enhancing competitive regional electric markets by increasing supply alternatives. The U.S. transmission grid was not designed to accommodate a restructured, competitive electric power industry and its function has transformed from one of delivering local generation to local distribution to the movement of electric power over long distances. To accommodate the scale of power transfers required to fulfill the Commission's goal of promoting effective wholesale markets competition and other policy objectives, transmission owners must do more than simply maintain their existing systems to perform the function for which they were designed; rather, they are being directed to literally redesign their transmissions systems. Thus, transmission owners, including Northern Pass and other regional utilities, will spend billions of dollars to upgrade and expand the existing transmission system.

In the past, transmission assets were treated no differently under traditional regulation than any other investment in electric utility plant. For purposes of establishing rates, investment in a utility's transmission system was included as a component of rate base, which determined the total amount of return

on capital used to establish rates. But considering the risks discussed earlier, the overall rate of return allowed regulated electric utilities has been insufficient to attract the level of capital investment deemed necessary to keep pace with these developments in the wholesale power markets.

Considering these factors and the specific circumstances of the NPT Line, an ROE in the upper end of the zone of reasonableness would be warranted for Northern Pass.

Q. HAS THE NEED TO INVEST IN THE NATION'S ELECTRIC TRANSMISSION INFRASTRUCTURE BEEN WELL DOCUMENTED?

A. Yes. There is little debate that increased investment in the transmission system will be required to fully realize the benefits of effective wholesale power markets. Concerns regarding the need to encourage further investment in the transmission sector were exemplified by the Commission's observations in *Order No. 679*:[97]

> [I]nvestment in transmission facilities in real dollar terms declined significantly between 1975 and 1998. Although the amount of investment has increased somewhat in the past few years, data for the most recent year available, 2003, shows investment levels still below the 1975 level in real dollars. This decline in transmission investment in real dollars has occurred while the electric load using the nation's grid more than doubled. Further, the record shows that the growth rate in transmission mileage since 1999 is not sufficient to meet the expected 50 percent growth in consumer demand for electricity over the next two decades.[98]

The challenges posed by an increasingly complex marketplace heighten the uncertainties associated with transmission operations while requiring the

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[97] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 ("Order No. 679"), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs.¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).
[98] *Order No. 679* at P 10.

commitment of significant new capital investment to maintain and enhance service capabilities. The Commission observed that the EPAct 2005 "put to rest" any conjecture regarding the need for incentives to promote increased capital spending on transmission facilities, and concluded that this mandate was supported by "abundant evidence."[99]

Q. WHAT IS THE LINK BETWEEN AN INCENTIVE-BASED ROE AND GREATER INVESTMENT IN TRANSMISSION INFRASTRUCTURE?

A. Consistent with the goals of Congress and established Commission policy, enhancements to an independently operated transmission grid under a regional plan will provide the benefits of improved reliability and further development of effective competition in the market for electricity. It is crucial that transmission owners such as Northern Pass be able to attract the economic resources necessary to meet these goals. Early on, the DOE noted the importance of regulatory policies in supporting economic rewards that stimulate investment in new transmission:

> The economic rewards from improving the transmission system must be greater than the rewards from maintaining the status quo or decreasing the system's ability to reliably support fair and efficient competitive wholesale markets. …The key to spurring new transmission investment lies in ensuring that the rewards offered by this system of regulation are commensurate with the risks of undertaking these investments and finding innovative approaches to align costs and benefits.[100]

Similarly, Value Line succinctly outlined the nexus between investors' expectations for allowed returns and increased investment in the transmission system:

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[99] *Id.* at P 14.
[100] U.S. Department of Energy, *National Transmission Grid Study* (May 2002).

> The domestic transmission & distribution system is showing its age and is in need of an upgrade. Several utilities now have large T&D projects under way. An adequate national upgrade will not occur unless state and federal regulators show an inclination to allow adequate returns on investment. Indeed, rate of returns granted by the states *do* appear to be edging upward. Federal allowed rates likely will move gradually higher as well.[101]

S&P has also noted the direct link between incentive-based rates and investment in transmission infrastructure, especially in light of the significant roadblocks to new transmission projects, including inadequate returns on capital.[102] S&P observed that the EPAct "provides financial and regulatory incentives to potential transmission constructors in an effort to boost investment in this segment of the utility industry," and concluded, "an increase in transmission construction seems promising."[103]

Q. HAS THE COMMISSION RECOGNIZED THAT AN INCENTIVE-BASED ROE WILL ATTRACT CAPITAL FOR NEW TRANSMISSION PROJECTS?

A. Yes. The Commission has recognized the importance of providing an ROE that overcomes obstacles to new transmission projects and encourages investment.[104] The Commission noted that transmission projects must compete for capital, and that an incentive ROE would provide an effective tool to foster new investments that increase grid reliability, reduce congestion, and advance environmental policy objectives. *Order No. 679* concluded that:

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[101] The Value Line Investment Survey (Mar. 3, 2006) at 155.
[102] Standard & Poor's Corporation, "Energy Policy Act Of 2005 May Spark More Electric Transmission Investment In U.S.," *RatingsDirect* (Mar. 30, 2006).
[103] *Id.*
[104] *Order No. 679* at P 91.

> [T]he Commission will approve an ROE at the upper end of the zone of reasonableness for new infrastructure investments that meet the requirements of section 219 as discussed elsewhere in this Final Rule.[105]

S&P observed that, despite the problems and uncertainties associated with transmission operations, investment has been "encouraged by financial incentives offered by [the Commission]."[106] More recently, S&P noted that "more than $75 billion of electric transmission projects are in various stages of planning as companies gravitate toward the [FERC]'s constructive regulatory polices including incentive returns on equity.[107] The corollary is that, absent a commitment to follow through on expectations for meaningful incentives embodied in the EPAct 2005 and the Commission's rulemaking, the flow of capital will diminish.

D. RTO Participation Adder

Q. HAS THE COMMISSION RECOGNIZED THAT AN ROE ADDER FOR PARTICIPATION IN AN RTO IS APPROPRIATE?

A. Yes. The EPAct specifically required the Commission to "provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization."[108] The decision to provide this incentive is well supported, both from policy and capital attraction reasons, and the Commission has consistently affirmed its support for an ROE incentive for participation in a Transmission

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[105] *Order No. 679* at PP 91, 92.
[106] Standard & Poor's Corporation, "Capital Spending On Electric Transmission Is On The Upswing Around The World," *RatingsDirect* (Aug. 7, 2007).
[107] Standard & Poor's Corporation, "Industry Report Card," *RatingsDirect* (Sep. 22, 2010).
[108] *Energy Policy Act of 2005*, 16 U.S.C. § 824s (c).

Organization.[109] The Commission has determined that the public interest is better served if functional control of the grid is performed by an independent entity like an RTO and if new transmission investment is undertaken with the wider focus and enhanced stakeholder participation provided through an independently-driven process, rather than under isolated, utility-by-utility planning.

In *Order No. 679*, the Commission stated that it will authorize, when justified, an incentive-based rate treatment, in the form of a higher ROE, for public utilities that join and/or continue to be a member of a Commission-approved Transmission Organization.[110] As the Commission noted:

> A regional planning process is very important to meeting regional transmission needs, and, we believe it will produce benefits for customers.[111]

While FERC elected to consider the incentive request on a case-by-case basis, rather than creating a generic adder, the Commission concluded that:

> [E]ntities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive. The basis for the incentive is a recognition of the benefits that flow from membership in such organizations and the fact continuing membership is generally voluntary.[112]

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[109] *See, e.g.*, *VEPCO* at P 67; *Bangor Hydro* at P 2; *Northern Pass Sys. Operating Cos.*, 106 FERC ¶ 61,003 at P 27 (2004); *PJM Interconnection*, *L.L.C.*, 104 FERC ¶ 61,124 at P 74 (2003).

[110] *Order No. 679* at P 326.

[111] *Order No. 679* at P 332.

[112] *Order No. 679* at P 331. Similarly, the Commission concluded in *Order No. 679-A,* "We affirm the finding in the Final Rule that the incentive applies to all utilities joining Transmission Organizations, irrespective of the date they join, based on a reading of section 219 in its entirety." (*Order No. 679-A* at P 86.)

The Commission has affirmed its policy of allowing an ROE adder to recognize the consumer benefits provided through membership in a Transmission Organization, and noted that a 50 basis point incentive was consistent with the level approved in other proceedings.[113]

Comprehensive operations, planning and decision making under the framework of a Transmission Organization should be encouraged, fostered, and rewarded in order to achieve the public policy goals mandated by Congress. Moreover, given past precedent authorizing incentive returns for Transmission Organization participants, investors have come to expect such added returns when they fund projects for which the utility is no longer the sole operational or planning entity. Incentive rate treatment to recognize that Northern Pass's jurisdictional transmission facilities will be operated within the scope of ISO-NE is consistent with past precedent, the Commission's guidelines, and investors' expectations and should be approved.

E. ROE Recommendation

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR ANALYSES.

A. The cost of common equity estimates produced by the analyses described in my testimony are summarized in Exhibit No. NPT-613.

Q. WHAT BASE ROE RANGE OF REASONABLENESS DOES YOUR EVALUATION INDICATE FOR NORTHERN PASS?

A. Taken together, my DCF results for the Regional and National Proxy Groups suggested a base ROE range of reasonableness on the order of 7.7 percent to 16.4 percent.

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[113] *See, e.g., Pepco Holdings, Inc.*, 121 FERC ¶ 61,169 at PP 15-16 (2007).

Q. IS THE REASONABLENESS OF THIS CONCLUSION SUPPORTED BY OTHER ROE BENCHMARKS?

A. Yes. Application of the DCF model to the Ratings Screen Proxy Group resulted in an adjusted range of reasonableness of 8.6 to 16.4 percent, while DCF results for a group of low-risk non-utility firms suggests a cost of equity range of 8.1 percent to 17.5 percent. Meanwhile, earned rates of return for the alternative proxy groups of utilities are anticipated to fall in the range of approximately 9.0 percent to 16.0 percent. Considering the Commission's policy goal of promoting increased infrastructure investment, these expected earned returns for electric utilities provide a meaningful benchmark in establishing an ROE for jurisdictional transmission operations that is sufficient to successfully compete for necessary capital investment. Considered along with the DCF results for the Non-Utility Proxy Group, and the need to consider flotation costs, they confirm my conclusion that a base ROE in the range of 7.7 percent to 16.4 percent is reasonable for Northern Pass.

Q. IS AN INCENTIVE-BASED ROE WARRANTED FOR THE NPT LINE?

A. Yes. The ROE specified by the TSA is one aspect of extensive negotiations between sophisticated parties and reflects the balance of risks and rewards necessary to finance development and construction of the NPT Line. Apart from this economic test of reasonableness, an incentive-based ROE from the upper end of the DCF zone is consistent with established Commission policy and warranted for Northern Pass. As Northern Pass has documented, it will face financial challenges in funding the significant new infrastructure investment associated with the NPT Line, along with other complexities and risks that distinguish this project from routine transmission investments.

As discussed in the testimony of the Company's witnesses, Northern Pass is unlike a traditional electric utility, in that it faces the considerable uncertainties associated with its lack of operating history, its ownership of a single-purpose facility serving a single, foreign customer, and other risks specific to the TSA. The Commission has previously determined that "a new and independent entity … bears a significant risk at the permitting and initial project development stage and in the start-up investment," and concluded that such higher risks require enhanced rate treatment.[114] An incentive-based ROE is consistent with the need for financial support as Northern Pass seeks to establish an investment grade credit standing while committing the capital investment necessary to undertake these important enhancements to the transmission infrastructure.

Q. DOES THE 12.56 PERCENT INITIAL ROE SPECIFIED FOR NORTHERN PASS MEET THE REQUIREMENTS OF ESTABLISHED COMMISSION POLCY?

A. Yes. Consistent with *Order Nos. 679* and *679-A,* this ROE falls well within the upper end of the adjusted ROE range of reasonableness produced by applying the Commission's DCF approach to the Regional and National Proxy Groups. Moreover, while the Commission noted that an ROE at the upper end of the reasonable range would not be justified in all cases, FERC also concluded that:

> In some instances, where the risks or challenges faced by a new investment are substantial, we may grant an ROE at the top end of the zone of reasonableness.[115]

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[114] *Trans Bay Cable* at P 25
[115] *Order No. 679-A* at P 67.

As documented in the testimony of the Company's other witnesses, the complexities of construction and scope of the investment associated with the NPT Line present substantial risks and challenges. Consistent with these special risks and the need to maintain the credit standing of Northern Pass and the participating utilities and ability to attract the necessary capital, an ROE from the upper end of the zone of reasonableness is warranted.

In evaluating a reasonable ROE range for Northern Pass, it is important to consider investors' continued focus on the unsettled conditions in the economy and capital markets, as well as ongoing developments in the electric utility industry, such as heightened exposure to regulatory risks. My conclusions are reinforced by the need to consider flotation costs, and the fact that current cost of capital estimates are likely to understate investors' requirements at the time the outcome of this proceeding becomes effective and beyond. Coupled with the need to provide an ROE that supports credit standing while funding substantial new investments in utility infrastructure, these considerations indicate that an incentive-based ROE of 12.56 percent for Northern Pass meets established policy guidelines and should be approved.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes, it does.

Exhibit Nos. NPT-601 to NPT-613

WILLIAM E. AVERA

FINCAP, INC.
Financial Concepts and Applications
Economic and Financial Counsel

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Summary of Qualifications

Ph.D. in economics and finance; Chartered Financial Analyst (CFA ®) designation; extensive expert witness testimony before courts, alternative dispute resolution panels, regulatory agencies and legislative committees; lectured in executive education programs around the world on ethics, investment analysis, and regulation; undergraduate and graduate teaching in business and economics; appointed to leadership positions in government, industry, academia, and the military.

Employment

Principal, FINCAP, Inc. (Sep. 1979 to present)	Financial, economic and policy consulting to business and government. Perform business and public policy research, cost/benefit analyses and financial modeling, valuation of businesses (almost 200 entities valued), estimation of damages, statistical and industry studies. Provide strategy advice and educational services in public and private sectors, and serve as expert witness before regulatory agencies, legislative committees, arbitration panels, and courts.
Director, Economic Research Division, Public Utility Commission of Texas (Dec. 1977 to Aug. 1979)	Responsible for research and testimony preparation on rate of return, rate structure, and econometric analysis dealing with energy, telecommunications, water and sewer utilities. Testified in major rate cases and appeared before legislative committees and served as Chief Economist for agency. Administered state and federal grant funds. Communicated frequently with political leaders and representatives from consumer groups, media, and investment community.
Manager, Financial Education, International Paper Company New York City (Feb. 1977 to Nov. 1977)	Directed corporate education programs in accounting, finance, and economics. Developed course materials, recruited and trained instructors, liaison within the company and with academic institutions. Prepared operating budget and designed financial controls for corporate professional development program.

Lecturer in Finance,
The University of Texas at Austin
(Sep. 1979 to May 1981)
Assistant Professor of Finance,
(Sep. 1975 to May 1977)

Taught graduate and undergraduate courses in financial management and investment theory. Conducted research in business and public policy. Named Outstanding Graduate Business Professor and received various administrative appointments.

Assistant Professor of Business,
University of North Carolina at Chapel Hill
(Sep. 1972 to Jul. 1975)

Taught in BBA, MBA, and Ph.D. programs. Created project course in finance, Financial Management for Women, and participated in developing Small Business Management sequence. Organized the North Carolina Institute for Investment Research, a group of financial institutions that supported academic research. Faculty advisor to the Media Board, which funds student publications and broadcast stations.

Education

Ph.D., Economics and Finance,
University of North Carolina at Chapel Hill
(Jan. 1969 to Aug. 1972)

Elective courses included financial management, public finance, monetary theory, and econometrics. Awarded the Stonier Fellowship by the American Bankers' Association and University Teaching Fellowship. Taught statistics, macroeconomics, and microeconomics.

Dissertation: *The Geometric Mean Strategy as a Theory of Multiperiod Portfolio Choice*

B.A., Economics,
Emory University, Atlanta, Georgia
(Sep. 1961 to Jun. 1965)

Active in extracurricular activities, president of the Barkley Forum (debate team), Emory Religious Association, and Delta Tau Delta chapter. Individual awards and team championships at national collegiate debate tournaments.

Professional Associations

Received Chartered Financial Analyst (CFA) designation in 1977; Vice President for Membership, Financial Management Association; President, Austin Chapter of Planning Executives Institute; Board of Directors, North Carolina Society of Financial Analysts; Candidate Curriculum Committee, Association for Investment Management and Research; Executive Committee of Southern Finance Association; Vice Chair, Staff Subcommittee on Economics and National Association of Regulatory Utility Commissioners (NARUC); Appointed to NARUC Technical Subcommittee on the National Energy Act.

Teaching in Executive Education Programs

University-Sponsored Programs: Central Michigan University, Duke University, Louisiana State University, National Defense University, National University of Singapore, Texas A&M University, University of Kansas, University of North Carolina, University of Texas.

Business and Government-Sponsored Programs: Advanced Seminar on Earnings Regulation, American Public Welfare Association, Association for Investment Management and Research, Congressional Fellows Program, Cost of Capital Workshop, Electricity Consumers Resource Council, Financial Analysts Association of Indonesia, Financial Analysts Review, Financial Analysts Seminar at Northwestern University, Governor's Executive Development Program of Texas, Louisiana Association of Business and Industry, National Association of Purchasing Management, National Association of Tire Dealers, Planning Executives Institute, School of Banking of the South, State of Wisconsin Investment Board, Stock Exchange of Thailand, Texas Association of State Sponsored Computer Centers, Texas Bankers' Association, Texas Bar Association, Texas Savings and Loan League, Texas Society of CPAs, Tokyo Association of Foreign Banks, Union Bank of Switzerland, U.S. Department of State, U.S. Navy, U.S. Veterans Administration, in addition to Texas state agencies and major corporations.

Presented papers for Mills B. Lane Lecture Series at the University of Georgia and Heubner Lectures at the University of Pennsylvania. Taught graduate courses in finance and economics for evening program at St. Edward's University in Austin from January 1979 through 1998.

Expert Witness Testimony

Testified in over 300 cases before regulatory agencies addressing cost of capital, regulatory policy, rate design, and other economic and financial issues.

Federal Agencies: Federal Communications Commission, Federal Energy Regulatory Commission, Surface Transportation Board, Interstate Commerce Commission, and the Canadian Radio-Television and Telecommunications Commission.

State Regulatory Agencies: Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Idaho, Illinois, Indiana, Iowa, Kansas, Kentucky, Maryland, Michigan, Missouri, Nevada, New Mexico, Montana, Nebraska, North Carolina, Ohio, Oklahoma, Oregon, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Virginia, Washington, West Virginia, Wisconsin, and Wyoming.

Testified in 42 cases before federal and state courts, arbitration panels, and alternative dispute tribunals (89 depositions given) regarding damages, valuation, antitrust liability, fiduciary duties, and other economic and financial issues.

Board Positions and Other Professional Activities

Audit Committee and Outside Director, Georgia System Operations Corporation (electric system operator for member-owned electric cooperatives in Georgia); Chairman, Board of Print Depot, Inc. and FINCAP, Inc.; Co-chair, Synchronous Interconnection Committee, appointed by Public Utility Commission of Texas and approved by governor; Appointed by Hays County Commission to Citizens Advisory Committee of Habitat Conservation Plan, Operator of AAA Ranch, a certified

organic producer of agricultural products; Appointed to Organic Livestock Advisory Committee by Texas Agricultural Commissioner Susan Combs; Appointed by Texas Railroad Commissioners to study group for *The UP/SP Merger: An Assessment of the Impacts on the State of Texas;* Appointed by Hawaii Public Utilities Commission to team reviewing affiliate relationships of Hawaiian Electric Industries; Chairman, Energy Task Force, Greater Austin-San Antonio Corridor Council; Consultant to Public Utility Commission of Texas on cogeneration policy and other matters; Consultant to Public Service Commission of New Mexico on cogeneration policy; Evaluator of Energy Research Grant Proposals for Texas Higher Education Coordinating Board.

Community Activities

Board of Directors, Sustainable Food Center; Chair, Board of Deacons, Finance Committee, and Elder, Central Presbyterian Church of Austin; Founding Member, Orange-Chatham County (N.C.) Legal Aid Screening Committee.

Military

Captain, U.S. Naval Reserve (retired after 28 years service); Commanding Officer, Naval Special Warfare Engineering (SEAL) Support Unit; Officer-in-Charge of SWIFT patrol boat in Vietnam; Enlisted service as weather analyst (advanced to second class petty officer).

Bibliography

Monographs

Ethics and the Investment Professional (video, workbook, and instructor's guide) and *Ethics Challenge Today* (video), Association for Investment Management and Research (1995)

"Definition of Industry Ethics and Development of a Code" and "Applying Ethics in the Real World," in *Good Ethics: The Essential Element of a Firm's Success,* Association for Investment Management and Research (1994)

"On the Use of Security Analysts' Growth Projections in the DCF Model," with Bruce H. Fairchild in *Earnings Regulation Under Inflation*, J. R. Foster and S. R. Holmberg, eds. Institute for Study of Regulation (1982)

An Examination of the Concept of Using Relative Customer Class Risk to Set Target Rates of Return in Electric Cost-of-Service Studies, with Bruce H. Fairchild, Electricity Consumers Resource Council (ELCON) (1981); portions reprinted in *Public Utilities Fortnightly* (Nov. 11, 1982)

"Usefulness of Current Values to Investors and Creditors," *Research Study on Current-Value Accounting Measurements and Utility*, George M. Scott, ed., Touche Ross Foundation (1978)

"The Geometric Mean Strategy and Common Stock Investment Management," with Henry A. Latané in *Life Insurance Investment Policies*, David Cummins, ed. (1977)

Investment Companies: Analysis of Current Operations and Future Prospects, with J. Finley Lee and Glenn L. Wood, American College of Life Underwriters (1975)

Articles

"Should Analysts Own the Stocks they Cover?" *The Financial Journalist*, (March 2002)

"Liquidity, Exchange Listing, and Common Stock Performance," with John C. Groth and Kerry Cooper, *Journal of Economics and Business* (Spring 1985); reprinted by National Association of Security Dealers

"The Energy Crisis and the Homeowner: The Grief Process," *Texas Business Review* (Jan.–Feb. 1980); reprinted in *The Energy Picture: Problems and Prospects*, J. E. Pluta, ed., Bureau of Business Research (1980)

"Use of IFPS at the Public Utility Commission of Texas," *Proceedings of the IFPS Users Group Annual Meeting* (1979)

"Production Capacity Allocation: Conversion, CWIP, and One-Armed Economics," *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"Some Thoughts on the Rate of Return to Public Utility Companies," with Bruce H. Fairchild in *Proceedings of the NARUC Biennial Regulatory Information Conference* (1978)

"A New Capital Budgeting Measure: The Integration of Time, Liquidity, and Uncertainty," with David Cordell in *Proceedings of the Southwestern Finance Association* (1977)

"Usefulness of Current Values to Investors and Creditors," in *Inflation Accounting/Indexing and Stock Behavior* (1977)

"Consumer Expectations and the Economy," *Texas Business Review* (Nov. 1976)

"Portfolio Performance Evaluation and Long-run Capital Growth," with Henry A. Latané in *Proceedings of the Eastern Finance Association* (1973)

Book reviews in *Journal of Finance* and *Financial Review*. Abstracts for *CFA Digest*. Articles in *Carolina Financial Times*.

Selected Papers and Presentations

"Economic Perspective on Water Marketing in Texas," 2009 Water Law Institute, The University of Texas School of Law, Austin, TX (Dec. 2009).

"Estimating Utility Cost of Equity in Financial Turmoil," SNL EXNET 15th Annual FERC Briefing, Washington, D.C. (Mar. 2009)

"The Who, What, When, How, and Why of Ethics," San Antonio Financial Analysts Society (Jan. 16, 2002). Similar presentation given to the Austin Society of Financial Analysts (Jan. 17, 2002)

"Ethics for Financial Analysts," Sponsored by Canadian Council of Financial Analysts: delivered in Calgary, Edmonton, Regina, and Winnipeg, June 1997. Similar presentations given to Austin Society of Financial Analysts (Mar. 1994), San Antonio Society of Financial Analysts (Nov. 1985), and St. Louis Society of Financial Analysts (Feb. 1986)

"Cost of Capital for Multi-Divisional Corporations," Financial Management Association, New Orleans, Louisiana (Oct. 1996)

"Ethics and the Treasury Function," Government Treasurers Organization of Texas, Corpus Christi, Texas (Jun. 1996)

"A Cooperative Future," Iowa Association of Electric Cooperatives, Des Moines (December 1995). Similar presentations given to National G & T Conference, Irving, Texas (June 1995), Kentucky Association of Electric Cooperatives Annual Meeting, Louisville (Nov. 1994), Virginia,

Maryland, and Delaware Association of Electric Cooperatives Annual Meeting, Richmond (July 1994), and Carolina Electric Cooperatives Annual Meeting, Raleigh (Mar. 1994)

"Information Superhighway Warnings: Speed Bumps on Wall Street and Detours from the Economy," Texas Society of Certified Public Accountants Natural Gas, Telecommunications and Electric Industries Conference, Austin (Apr. 1995)

"Economic/Wall Street Outlook," Carolinas Council of the Institute of Management Accountants, Myrtle Beach, South Carolina (May 1994). Similar presentation given to Bell Operating Company Accounting Witness Conference, Santa Fe, New Mexico (Apr. 1993)

"Regulatory Developments in Telecommunications," Regional Holding Company Financial and Accounting Conference, San Antonio (Sep. 1993)

"Estimating the Cost of Capital During the 1990s: Issues and Directions," The National Society of Rate of Return Analysts, Washington, D.C. (May 1992)

"Making Utility Regulation Work at the Public Utility Commission of Texas," Center for Legal and Regulatory Studies, University of Texas, Austin (June 1991)

"Can Regulation Compete for the Hearts and Minds of Industrial Customers," Emerging Issues of Competition in the Electric Utility Industry Conference, Austin (May 1988)

"The Role of Utilities in Fostering New Energy Technologies," Emerging Energy Technologies in Texas Conference, Austin (Mar. 1988)

"The Regulators' Perspective," Bellcore Economic Analysis Conference, San Antonio (Nov. 1987)

"Public Utility Commissions and the Nuclear Plant Contractor," Construction Litigation Superconference, Laguna Beach, California (Dec. 1986)

"Development of Cogeneration Policies in Texas," University of Georgia Fifth Annual Public Utilities Conference, Atlanta (Sep. 1985)

"Wheeling for Power Sales," Energy Bureau Cogeneration Conference, Houston (Nov. 1985).

"Asymmetric Discounting of Information and Relative Liquidity: Some Empirical Evidence for Common Stocks" (with John Groth and Kerry Cooper), Southern Finance Association, New Orleans (Nov. 1982)

"Used and Useful Planning Models," Planning Executive Institute, 27th Corporate Planning Conference, Los Angeles (Nov. 1979)

"Staff Input to Commission Rate of Return Decisions," The National Society of Rate of Return Analysts, New York (Oct. 1979)

""Discounted Cash Life: A New Measure of the Time Dimension in Capital Budgeting," with David Cordell, Southern Finance Association, New Orleans (Nov. 1978)

"The Relative Value of Statistics of Ex Post Common Stock Distributions to Explain Variance," with Charles G. Martin, Southern Finance Association, Atlanta (Nov. 1977)

"An ANOVA Representation of Common Stock Returns as a Framework for the Allocation of Portfolio Management Effort," with Charles G. Martin, Financial Management Association, Montreal (Oct. 1976)

"A Growth-Optimal Portfolio Selection Model with Finite Horizon," with Henry A. Latané, American Finance Association, San Francisco (Dec. 1974)

"An Optimal Approach to the Finance Decision," with Henry A. Latané, Southern Finance Association, Atlanta (Nov. 1974)

"A Pragmatic Approach to the Capital Structure Decision Based on Long-Run Growth," with Henry A. Latané, Financial Management Association, San Diego (Oct. 1974)

"Growth Rates, Expected Returns, and Variance in Portfolio Selection and Performance Evaluation," with Henry A. Latané, Econometric Society, Oslo, Norway (Aug. 1973)

PROXY GROUP RISK MEASURES

NATIONAL PROXY GROUP

			(a)	(b)								
			S&P	**Value Line**			**Industry Classification**					
			Credit	**Safety**	**Financial**		**Value Line** (b)		**S&P** (c)		**IBES** (d)	
	Company	**SYM**	**Rating**	**Rank**	**Strength**	**Beta**	**Sector**	**Sub-Industry**	**Sector**	**Sub-Industry**	**Sector**	**Sub-Industry**
1	Ameren Corp.	AEE	BBB-	3	B++	0.80	Electric Utility	Central	Utilities	Multi-Utilities	Utilities	Multiutilities
2	American Elec Pwr	AEP	BBB	3	B++	0.70	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
3	Avista Corp.	AVA	BBB-	2	B++	0.70	Electric Utility	West	Utilities	Multi-Utilities	Utilities	Multiutilities
4	Black Hills Corp.	BKH	BBB-	3	B+	0.80	Electric Utility	West	Utilities	Multi-Utilities	Utilities	Electricity
5	CenterPoint Energy	CNP	BBB	3	B	0.80	Electric Utility	Central	Utilities	Multi-Utilities	Utilities	Multiutilities
6	Cleco Corp.	CNL	BBB	3	B+	0.65	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
7	CMS Energy	CMS	BBB-	3	B	0.75	Electric Utility	Central	Utilities	Multi-Utilities	Utilities	Electricity
8	DTE Energy Co.	DTE	BBB	3	B+	0.75	Electric Utility	Central	Utilities	Multi-Utilities	Utilities	Electricity
9	Edison International	EIX	BBB-	3	B++	0.80	Electric Utility	West	Utilities	Electric Utilities	Utilities	Electricity
10	Great Plains Energy	GXP	BBB	3	B+	0.75	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
11	Hawaiian Elec.	HE	BBB-	3	B+	0.70	Electric Utility	West	Utilities	Electric Utilities	Utilities	Electricity
12	IDACORP, Inc.	IDA	BBB	3	B+	0.70	Electric Utility	West	Utilities	Electric Utilities	Utilities	Electricity
13	Integrys Energy Group	TEG	BBB	3	B+	0.90	Electric Utility	Central	Utilities	Multi-Utilities	Utilities	Multiutilities
14	ITC Holdings Corp.	ITC	BBB	3	B	0.80	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
15	Pepco Holdings	POM	BBB+	3	B	0.80	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
16	PG&E Corp.	PCG	BBB+	2	B++	0.55	Electric Utility	West	Utilities	Multi-Utilities	Utilities	Electricity
17	Pinnacle West Capital	PNW	BBB-	3	B+	0.70	Electric Utility	West	Utilities	Electric Utilities	Utilities	Electricity
18	Portland General Elec.	POR	BBB	3	B+	0.75	Electric Utility	West	Utilities	Electric Utilities	Utilities	Electricity
19	PPL Corp.	PPL	BBB+	3	B++	0.70	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
20	Progress Energy	PGN	BBB+	2	B++	0.60	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
21	TECO Energy	TE	BBB	3	B	0.85	Electric Utility	East	Utilities	Multi-Utilities	Utilities	Electricity
22	UIL Holdings	UIL	BBB	2	B++	0.70	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
23	Westar Energy	WR	BBB	2	B++	0.75	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
24	Wisconsin Energy	WEC	BBB+	2	B++	0.65	Electric Utility	Central	Utilities	Multi-Utilities	Utilities	Multiutilities
			BBB	**3**	**B+**	**0.74**						

(a) www.standardandpoors.com (retrieved Dec. 7, 2010)
(b) www.valueline.com (retrieved Dec. 7, 2010).
(c) Standard and Poor's Corporation, *Stock Report* (retrieved from www.fidelity.com Dec. 9, 2010).
(d) *Thompson Reuters Company in Context Report* (Dec. 7, 2010).

PROXY GROUP RISK MEASURES

REGIONAL PROXY GROUP

				(a)	(b)								
				S&P	**Value Line**			**Industry Classification**					
				Credit	**Safety**	**Financial**		**Value Line** (b)		**S&P** (c)		**IBES** (d)	
	Company	**SYM**	**RTO**	**Rating**	**Rank**	**Strength**	**Beta**	**Sector**	**Sub-Industry**	**Sector**	**Sub-Industry**	**Sector**	**Sub-Industry**
1	American Elec Pwr	AEP	PJM	BBB	3	B++	0.70	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
2	Consolidated Edison	ED	PJM/NYISO	A-	1	A+	0.65	Electric Utility	East	Utilities	Multi-Utilities	Utilities	Electricity
3	Dominion Resources	D	PJM	A-	2	B++	0.70	Electric Utility	East	Utilities	Multi-Utilities	Utilities	Electricity
4	DPL, Inc.	DPL	PJM	A-	3	B++	0.60	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
5	Exelon Corp.	EXC	PJM	BBB	1	A+	0.85	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
6	NextEra Energy	NEE	ISO-NE	A-	2	A	0.75	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
8	Pepco Holdings	POM	PJM	BBB+	3	B	0.80	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
7	PPL Corp.	PPL	BBB	BBB	3	B++	0.70	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
9	Pub Sv Enterprise Grp	PEG	PJM	BBB	2	A	0.80	Electric Utility	East	Utilities	Multi-Utilities	Utilities	Electricity
10	UIL Holdings	UIL	ISO-NE	BBB	2	B++	0.70	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
				BBB+	**2**	**B++**	0.73						

(a) www.standardandpoors.com (retrieved Dec. 7, 2010).
(b) www.valueline.com (retrieved Dec. 7, 2010).
(c) Standard and Poor's Corporation, *Stock Report* (retrieved from www.fidelity.com Dec. 9, 2010).
(d) *Thompson Reuters Company in Context Report* (Dec. 7, 2010).

PROXY GROUP RISK MEASURES

RATINGS SCREEN PROXY GROUP

				(a)	(b)								
				S&P	**Value Line**			**Industry Classification**					
				Credit	**Safety**	**Financial**		**Value Line** (b)		**S&P** (c)		**IBES** (d)	
	Company	**SYM**	**RTO**	**Rating**	**Rank**	**Strength**	**Beta**	**Sector**	**Sub-Industry**	**Sector**	**Sub-Industry**	**Sector**	**Sub-Industry**
1	American Elec Pwr	AEP	PJM	BBB	3	B++	0.70	Electric Utility	Central	Utilities	Electric Utilities	Utilities	Electricity
2	Exelon Corp.	EXC	PJM	BBB	1	A+	0.85	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
3	Pepco Holdings	POM	PJM	BBB+	3	B	0.80	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
4	PPL Corp.	PPL	BBB	BBB	3	B++	0.70	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
5	Pub Sv Enterprise Grp	PEG	PJM	BBB	2	A	0.80	Electric Utility	East	Utilities	Multi-Utilities	Utilities	Electricity
6	UIL Holdings	UIL	ISO-NE	BBB	2	B++	0.70	Electric Utility	East	Utilities	Electric Utilities	Utilities	Electricity
				BBB	**2**	**B++**	0.76						

(a) www.standardandpoors.com (retrieved Dec. 7, 2010).
(b) www.valueline.com (retrieved Dec. 7, 2010).
(c) Standard and Poor's Corporation, *Stock Report* (retrieved from www.fidelity.com Dec. 9, 2010).
(d) *Thompson Reuters Company in Context Report* (Dec. 7, 2010).

FERC DCF MODEL

NATIONAL PROXY GROUP

		(a)		(b)		(c)	(d)				
		6 Mo.Div. Yield		Adjusted Div. Yield		Growth Rates		Implied Cost of Equity			
	Company	Low	High	Low	High	br + sv	IBES	Low		High	Average
1	Ameren Corp.	5.5%	5.9%	5.4%	6.0%	2.5%	-3.9%	1.5%	--	8.5%	--
2	American Elec Pwr	4.7%	5.0%	4.7%	5.1%	4.5%	3.9%	8.6%	--	9.6%	9.1%
3	Avista Corp.	4.6%	5.0%	4.7%	5.1%	3.6%	4.5%	8.3%	--	9.6%	8.9%
4	Black Hills Corp.	4.4%	5.0%	4.5%	5.1%	1.7%	6.0%	6.2%	--	11.1%	--
5	CenterPoint Energy	5.0%	5.5%	5.2%	5.7%	8.0%	5.8%	11.0%	--	13.7%	12.4%
6	Cleco Corp.	3.3%	3.5%	3.3%	3.7%	6.2%	3.0%	6.3%	--	9.8%	--
7	CMS Energy	3.6%	4.0%	3.7%	4.1%	5.3%	6.0%	9.0%	--	10.1%	9.5%
8	DTE Energy Co.	4.5%	4.9%	4.6%	5.0%	4.2%	5.0%	8.9%	--	10.0%	9.4%
9	Edison International	3.5%	3.8%	3.6%	3.9%	5.5%	3.5%	7.1%	--	9.4%	--
10	Great Plains Energy	4.4%	4.7%	4.5%	5.0%	2.7%	13.0%	7.1%	--	18.0%	--
11	Hawaiian Elec.	5.2%	5.6%	5.2%	5.8%	2.3%	8.0%	7.5%	--	13.8%	--
12	IDACORP, Inc.	3.3%	3.5%	3.3%	3.6%	5.5%	4.7%	8.0%	--	9.1%	8.6%
13	Integrys Energy Grp	5.3%	5.8%	5.4%	6.0%	1.8%	7.9%	7.1%	--	13.9%	--
14	ITC Holdings Corp.	2.2%	2.4%	2.3%	2.6%	10.0%	16.5%	12.3%	--	19.1%	--
15	Pepco Holdings	5.9%	6.4%	5.9%	6.6%	0.7%	7.0%	6.5%	--	13.6%	--
16	PG&E Corp.	3.9%	4.2%	4.0%	4.4%	6.0%	6.5%	9.9%	--	10.9%	10.4%
17	Pinnacle West Capital	5.1%	5.5%	5.2%	5.7%	3.5%	6.5%	8.7%	--	12.2%	10.5%
18	Portland General Elec.	5.1%	5.4%	5.1%	5.5%	3.4%	5.4%	8.5%	--	10.9%	9.7%
19	PPL Corp.	5.1%	5.5%	5.2%	5.8%	10.6%	3.6%	8.8%	--	16.4%	12.6%
20	Progress Energy	5.7%	6.1%	5.7%	6.2%	2.0%	3.7%	7.7%	--	9.9%	8.8%
21	TECO Energy	4.7%	5.1%	4.8%	5.3%	4.9%	6.8%	9.7%	--	12.1%	10.9%
22	UIL Holdings	6.1%	6.6%	6.2%	6.8%	5.7%	3.7%	9.9%	--	12.5%	11.2%
23	Westar Energy	5.0%	5.4%	5.1%	5.6%	2.8%	7.8%	7.9%	--	13.4%	10.7%
24	Wisconsin Energy	2.8%	3.0%	2.9%	3.1%	7.0%	10.1%	9.9%	--	13.2%	11.6%
	Range of Reasonableness							**1.5%**	--	**19.1%**	
	Adjusted Range of Reasonableness (e)							**7.7%**	--	**16.4%**	
	Midpoint							**12.1%**			
	Median (f)										**10.4%**

(a) Six-month average dividend yield for June - November 2010.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) See Exhibit No. NPT-604.
(d) *Thompson Reuters Company in Context Report* (Dec. 7, 2010).
(e) Excludes highlighted values.
(f) Based on the average of the low and high DCF estimates for all companies with two valid observations.

BR + SV GROWTH RATE

Exhibit No. NPT-604
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NATIONAL PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(c)	(c)	(d)	(e)		
				2010				2011				2014			Adjustment			Avg	Avg
	Company	EPS	DPS	b	r	EPS	DPS	b	r	EPS	DPS	b	r	Avg b	Avg r	Factor	Adjstd r	br	br + sv
1	Ameren Corp.	$2.50	$1.54	38.4%	7.5%	$2.50	$1.54	38.4%	7.0%	$2.50	$1.54	38.4%	7.0%	38.4%	7.2%	1.0200	7.3%	2.8%	**2.5%**
2	American Elec Pwr	$2.55	$1.67	34.5%	9.0%	$3.15	$1.70	46.0%	10.5%	$3.50	$1.90	45.7%	10.0%	42.1%	9.8%	1.0325	10.2%	4.3%	**4.5%**
3	Avista Corp.	$1.65	$1.00	39.4%	8.0%	$1.70	$1.08	36.5%	8.0%	$2.00	$1.30	35.0%	9.0%	37.0%	8.3%	1.0252	8.5%	3.2%	**3.6%**
4	Black Hills Corp.	$1.50	$1.44	4.0%	5.5%	$2.00	$1.48	26.0%	7.0%	$2.25	$1.60	28.9%	7.5%	19.6%	6.7%	1.0211	6.8%	1.3%	**1.7%**
5	CenterPoint Energy	$1.05	$0.78	25.7%	13.5%	$1.20	$0.80	33.3%	15.0%	$1.50	$0.90	40.0%	14.5%	33.0%	14.3%	1.0560	15.1%	5.0%	**8.0%**
6	Cleco Corp.	$2.45	$0.98	60.0%	11.0%	$2.35	$1.08	54.0%	10.5%	$2.75	$1.45	47.3%	10.5%	53.8%	10.7%	1.0420	11.1%	6.0%	**6.2%**
7	CMS Energy	$1.30	$0.72	44.6%	11.5%	$1.45	$0.84	42.1%	12.0%	$1.65	$1.00	39.4%	12.0%	42.0%	11.8%	1.0295	12.2%	5.1%	**5.3%**
8	DTE Energy Co.	$3.80	$2.18	42.6%	9.5%	$3.85	$2.30	40.3%	9.5%	$4.25	$2.70	36.5%	9.5%	39.8%	9.5%	1.0278	9.8%	3.9%	**4.2%**
9	Edison International	$3.25	$1.28	60.6%	10.0%	$3.25	$1.34	58.8%	9.5%	$3.25	$1.50	53.8%	8.5%	57.7%	9.3%	1.0263	9.6%	5.5%	**5.5%**
10	Great Plains Energy	$1.50	$0.83	44.7%	7.0%	$1.50	$0.87	42.0%	7.0%	$1.75	$1.15	34.3%	7.5%	40.3%	7.2%	1.0247	7.3%	3.0%	**2.7%**
11	Hawaiian Elec.	$1.30	$1.24	4.6%	8.0%	$1.50	$1.24	17.3%	9.0%	$2.00	$1.30	35.0%	10.5%	19.0%	9.2%	1.0220	9.4%	1.8%	**2.3%**
12	IDACORP, Inc.	$2.85	$1.20	57.9%	9.5%	$2.90	$1.20	58.6%	9.0%	$3.10	$1.40	54.8%	8.5%	57.1%	9.0%	1.0303	9.3%	5.3%	**5.5%**
13	Integrys Energy Grp	$2.95	$2.72	7.8%	8.0%	$3.30	$2.72	17.6%	8.5%	$4.00	$2.72	32.0%	9.5%	19.1%	8.7%	1.0136	8.8%	1.7%	**1.8%**
14	ITC Holdings Corp.	$2.75	$1.31	52.4%	13.0%	$3.20	$1.37	57.2%	14.0%	$4.50	$1.65	63.3%	15.0%	57.6%	14.0%	1.0467	14.7%	8.4%	**10.0%**
15	Pepco Holdings	$1.07	$1.08	-0.9%	5.5%	$1.15	$1.08	6.1%	6.0%	$1.55	$1.12	27.7%	7.5%	11.0%	6.3%	1.0180	6.4%	0.7%	**0.7%**
16	PG&E Corp.	$3.00	$1.82	39.3%	10.5%	$3.50	$1.92	45.1%	11.5%	$4.25	$2.20	48.2%	12.0%	44.2%	11.3%	1.0401	11.8%	5.2%	**6.0%**
17	Pinnacle West Capital	$3.10	$2.10	32.3%	9.0%	$3.15	$2.10	33.3%	9.0%	$3.50	$2.30	34.3%	9.0%	33.3%	9.0%	1.0351	9.3%	3.1%	**3.5%**
18	Portland General Elec.	$1.70	$1.04	38.8%	8.0%	$1.75	$1.07	38.9%	7.0%	$2.00	$1.20	40.0%	8.5%	39.2%	7.8%	1.0327	8.1%	3.2%	**3.4%**
19	PPL Corp.	$2.15	$1.40	34.9%	11.5%	$2.25	$1.40	37.8%	12.5%	$2.50	$1.60	36.0%	11.5%	36.2%	11.8%	1.0816	12.8%	4.6%	**10.6%**
20	Progress Energy	$3.00	$2.48	17.3%	8.5%	$3.15	$2.52	20.0%	8.5%	$3.55	$2.58	27.3%	9.0%	21.6%	8.7%	1.0248	8.9%	1.9%	**2.0%**
21	TECO Energy	$1.20	$0.82	31.7%	12.0%	$1.30	$0.84	35.4%	12.5%	$1.60	$0.95	40.6%	13.0%	35.9%	12.5%	1.0263	12.8%	4.6%	**4.9%**
22	UIL Holdings	$2.00	$1.73	13.5%	10.0%	$2.15	$1.73	19.5%	9.0%	$2.35	$1.73	26.4%	9.0%	19.8%	9.3%	1.0831	10.1%	2.0%	**5.7%**
23	Westar Energy	$1.75	$1.24	29.1%	8.5%	$1.85	$1.28	30.8%	8.0%	$2.25	$1.40	37.8%	8.5%	32.6%	8.3%	1.0281	8.6%	2.8%	**2.8%**
24	Wisconsin Energy	$3.70	$1.60	56.8%	11.5%	$4.10	$1.80	56.1%	12.0%	$5.25	$2.40	54.3%	13.0%	55.7%	12.2%	1.0313	12.5%	7.0%	**7.0%**

BR + SV GROWTH RATE

NATIONAL PROXY GROUP

		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(a)	(h)	(a)	(a)	(g)	(i)	(j)	
		----------	2009	----------	----------	2014	----------	Chg	---------	2014 Price	---------	2014		------	No. Shares	------	--------	"sv" Factor	--------
	Company	Eq Ratio	Tot Cap	Com Eq	Eq Ratio	Tot Cap	Com Eq	Equity	High	Low	Avg.	BVPS	M/B	2009	2014	Growth	s	v	sv
1	Ameren Corp.	49.1%	$15,991	$7,852	53.0%	$18,100	$9,593	4.1%	$35.00	$25.00	$30.00	$37.50	0.800	237.4	255.0	1.44%	0.0115	(0.2500)	-0.29%
2	American Elec Pwr	45.4%	$28,958	$13,147	47.5%	$38,300	$18,193	6.7%	$50.00	$35.00	$42.50	$34.75	1.223	478.1	500.0	0.90%	0.0110	0.1824	0.20%
3	Avista Corp.	49.1%	$2,139	$1,050	50.5%	$2,675	$1,351	5.2%	$30.00	$25.00	$27.50	$22.50	1.222	54.8	60.0	1.81%	0.0222	0.1818	0.40%
4	Black Hills Corp.	51.6%	$2,101	$1,084	50.5%	$2,650	$1,338	4.3%	$40.00	$30.00	$35.00	$30.50	1.148	39.0	44.3	2.57%	0.0295	0.1286	0.38%
5	CenterPoint Energy	22.4%	$11,758	$2,634	32.5%	$14,200	$4,615	11.9%	$25.00	$15.00	$20.00	$10.00	2.000	391.8	455.0	3.04%	0.0608	0.5000	3.04%
6	Cleco Corp.	45.8%	$2,436	$1,116	53.5%	$3,175	$1,699	8.8%	$35.00	$25.00	$30.00	$26.25	1.143	60.3	65.0	1.53%	0.0174	0.1250	0.22%
7	CMS Energy	29.0%	$8,977	$2,603	31.5%	$11,100	$3,497	6.1%	$25.00	$16.00	$20.50	$15.25	1.344	227.9	233.0	0.44%	0.0060	0.2561	0.15%
8	DTE Energy Co.	46.0%	$13,648	$6,278	48.5%	$17,100	$8,294	5.7%	$70.00	$45.00	$57.50	$46.50	1.237	165.4	178.0	1.48%	0.0183	0.1913	0.35%
9	Edison International	46.5%	$21,185	$9,851	44.5%	$28,800	$12,816	5.4%	$50.00	$35.00	$42.50	$39.50	1.076	325.8	325.8	0.00%	-	0.0706	0.00%
10	Great Plains Energy	46.2%	$6,045	$2,793	46.0%	$7,775	$3,577	5.1%	$25.00	$16.00	$20.50	$22.50	0.911	135.4	159.0	3.26%	0.0297	(0.0976)	-0.29%
11	Hawaiian Elec.	50.7%	$2,841	$1,440	52.0%	$3,450	$1,794	4.5%	$30.00	$19.00	$24.50	$18.00	1.361	92.5	99.0	1.36%	0.0186	0.2653	0.49%
12	IDACORP, Inc.	49.8%	$2,807	$1,398	50.5%	$3,750	$1,894	6.3%	$50.00	$30.00	$40.00	$36.50	1.096	47.9	52.0	1.66%	0.0181	0.0875	0.16%
13	Integrys Energy Grp	53.9%	$5,304	$2,859	51.0%	$6,425	$3,277	2.8%	$55.00	$40.00	$47.50	$41.50	1.145	76.0	78.5	0.65%	0.0075	0.1263	0.09%
14	ITC Holdings Corp.	29.4%	$3,446	$1,013	29.0%	$5,575	$1,617	9.8%	$100.00	$65.00	$82.50	$31.00	2.661	50.1	52.5	0.95%	0.0252	0.6242	1.58%
15	Pepco Holdings	46.2%	$9,203	$4,252	48.0%	$10,600	$5,088	3.7%	$25.00	$16.00	$20.50	$21.25	0.965	222.3	240.0	1.55%	0.0149	(0.0366)	-0.05%
16	PG&E Corp.	47.4%	$21,793	$10,330	54.5%	$28,300	$15,424	8.3%	$55.00	$40.00	$47.50	$36.75	1.293	370.6	420.0	2.53%	0.0328	0.2263	0.74%
17	Pinnacle West Capital	49.6%	$6,687	$3,317	54.0%	$8,725	$4,712	7.3%	$50.00	$35.00	$42.50	$38.50	1.104	101.4	122.0	3.76%	0.0415	0.0941	0.39%
18	Portland General Elec.	49.7%	$3,100	$1,541	50.0%	$4,275	$2,138	6.8%	$30.00	$20.00	$25.00	$23.75	1.053	75.2	90.0	3.66%	0.0385	0.0500	0.19%
19	PPL Corp.	42.5%	$12,940	$5,500	53.5%	$23,300	$12,466	17.8%	$45.00	$30.00	$37.50	$22.00	1.705	377.2	565.0	8.42%	0.1435	0.4133	5.93%
20	Progress Energy	43.3%	$21,593	$9,350	47.0%	$25,500	$11,985	5.1%	$50.00	$35.00	$42.50	$40.00	1.063	281.0	300.0	1.32%	0.0140	0.0588	0.08%
21	TECO Energy	39.4%	$5,287	$2,083	42.0%	$6,450	$2,709	5.4%	$25.00	$16.00	$20.50	$12.25	1.673	213.9	219.0	0.47%	0.0079	0.4024	0.32%
22	UIL Holdings	46.0%	$1,248	$574	40.0%	$3,300	$1,320	18.1%	$40.00	$30.00	$35.00	$26.00	1.346	30.0	50.0	10.77%	0.1450	0.2571	3.73%
23	Westar Energy	47.4%	$4,778	$2,265	46.0%	$6,520	$2,999	5.8%	$30.00	$25.00	$27.50	$26.10	1.054	109.1	115.0	1.06%	0.0112	0.0509	0.06%
24	Wisconsin Energy	47.7%	$7,473	$3,565	50.5%	$9,650	$4,873	6.5%	$80.00	$60.00	$70.00	$41.50	1.687	116.9	116.9	0.00%	(0.0000)	0.4071	0.00%

(a) The Value Line Investment Survey (Sep. 24, Nov. 5, & Nov. 26, 2010).
(b) Computed as (EPS - DPS) / EPS.
(c) Average of values for 2010, 2011, and 2013-15.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2010, 2011, and 2013-15 and Adjustment Factor.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2013-15 BVPS.
(i) Product of change in common shares outstanding and M/B Ratio.
(j) Computed as 1 - B/M Ratio.

FERC DCF MODEL

REGIONAL PROXY GROUP

		(a)		(b)		(c)	(d)	(e)		(f)	
		6 Mo.Div. Yield		**Adjusted Div. Yield**		**Growth Rates**		**Implied Cost of Equity**			
	Company	**Low**	**High**	**Low**	**High**	**br + sv**	**IBES**	**Low**		**High**	**Average**
1	American Elec Pwr	4.7%	5.0%	4.7%	5.1%	4.5%	3.9%	8.6%	--	9.6%	9.1%
2	Consolidated Edison	4.9%	5.2%	5.0%	5.4%	3.8%	4.3%	8.8%	--	9.7%	9.2%
3	Dominion Resources	4.2%	4.5%	4.2%	4.6%	5.4%	3.5%	7.7%	--	10.0%	8.8%
4	DPL, Inc.	4.5%	4.9%	4.7%	5.3%	15.2%	5.9%	10.6%	--	20.5%	--
5	Exelon Corp.	4.9%	5.4%	4.8%	5.6%	7.1%	-2.4%	2.4%	--	12.6%	--
6	NextEra Energy	3.6%	4.0%	3.8%	4.1%	8.0%	6.6%	10.4%	--	12.1%	11.2%
8	Pepco Holdings	5.9%	6.4%	5.9%	6.6%	0.7%	7.0%	6.5%	--	13.6%	--
7	PPL Corp.	5.1%	5.5%	5.2%	5.8%	10.6%	3.6%	8.8%	--	16.4%	12.6%
9	Pub Sv Enterprise Grp	4.0%	4.4%	4.1%	4.6%	8.3%	2.0%	6.1%	--	12.9%	--
10	UIL Holdings	6.1%	6.6%	6.2%	6.8%	5.7%	3.7%	9.9%	--	12.5%	11.2%
	Range of Reasonableness							**2.4%**	--	**20.5%**	
	Adjusted Range of Reasonableness (g)							**7.7%**	--	**16.4%**	
	Midpoint								**12.1%**		
	Median (f)										**10.2%**

(a) Six-month average dividend yield for June - November 2010.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) See Exhibit No. NPT-606.
(d) *Thompson Reuters Company in Context Report* (Dec. 7, 2010).
(e) Excludes highlighted values.
(f) Based on the average of the low and high DCF estimates for all companies with two valid observations.

BR + SV GROWTH RATE

Exhibit No. NPT-606
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REGIONAL PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(c)	(c)	(d)	(e)		
				2010				2011				2014			Adjustment			Avg	Avg
	Company	EPS	DPS	b	r	EPS	DPS	b	r	EPS	DPS	b	r	Avg b	Avg r	Factor	Adjstd r	br	br + sv
1	American Elec Pwr	$2.55	$1.67	34.5%	9.0%	$3.15	$1.70	46.0%	10.5%	$3.50	$1.90	45.7%	10.0%	42.1%	9.8%	1.0325	10.2%	4.3%	**4.5%**
2	Consolidated Edison	$3.45	$2.38	31.0%	9.5%	$3.55	$2.40	32.4%	9.5%	$3.90	$2.46	36.9%	9.5%	33.4%	9.5%	1.0220	9.7%	3.2%	**3.8%**
3	Dominion Resources	$2.90	$1.83	36.9%	14.0%	$3.20	$1.97	38.4%	14.5%	$3.75	$2.40	36.0%	14.5%	37.1%	14.3%	1.0366	14.9%	5.5%	**5.4%**
4	DPL, Inc.	$2.45	$1.21	50.6%	24.5%	$2.65	$1.28	51.7%	25.0%	$3.00	$1.50	50.0%	25.5%	50.8%	25.0%	1.0307	25.8%	13.1%	**15.2%**
5	Exelon Corp.	$4.00	$2.10	47.5%	19.0%	$4.00	$2.10	47.5%	17.5%	$3.50	$2.10	40.0%	14.0%	45.0%	16.8%	1.0240	17.2%	7.8%	**7.1%**
6	NextEra Energy, Inc.	$4.95	$2.00	59.6%	14.5%	$4.30	$2.10	51.2%	11.5%	$5.25	$2.40	54.3%	11.5%	55.0%	12.5%	1.0441	13.1%	7.2%	**8.0%**
8	Pepco Holdings	$1.07	$1.08	-0.9%	5.5%	$1.15	$1.08	6.1%	6.0%	$1.55	$1.12	27.7%	7.5%	11.0%	6.3%	1.0180	6.4%	0.7%	**0.7%**
7	PPL Corp.	$2.15	$1.40	34.9%	11.5%	$2.25	$1.40	37.8%	12.5%	$2.50	$1.60	36.0%	11.5%	36.2%	11.8%	1.0816	12.8%	4.6%	**10.6%**
9	Pub Sv Enterprise Grp	$3.05	$1.37	55.1%	16.0%	$3.15	$1.40	55.6%	15.0%	$3.25	$1.50	53.8%	12.5%	54.8%	14.5%	1.0398	15.1%	8.3%	**8.3%**
10	UIL Holdings	$2.00	$1.73	13.5%	10.0%	$2.15	$1.73	19.5%	9.0%	$2.35	$1.73	26.4%	9.0%	19.8%	9.3%	1.0831	10.1%	2.0%	**5.7%**

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		(a)	(a)	(f)	(a)	(a)	(f)	(g)	(a)	(a)		(a)	(h)	(a)	(a)	(g)	(i)	(j)	
		----------	2009	----------	----------	2014	----------	Chg	---------	2014 Price	---------	2014		------	No. Shares	------	--------	"sv" Factor	--------
	Company	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Eq Ratio**	**Tot Cap**	**Com Eq**	**Equity**	**High**	**Low**	**Avg.**	**BVPS**	**M/B**	**2009**	**2014**	**Growth**	**s**	**v**	**sv**
1	American Elec Pwr	45.4%	$28,958	$13,147	47.5%	$38,300	$18,193	6.7%	$50.00	$35.00	$42.50	$34.75	1.223	478.1	500.0	0.90%	0.0110	0.1824	0.20%
2	Consolidated Edison	51.0%	$20,103	$10,253	51.5%	$24,800	$12,772	4.5%	$60.00	$45.00	$52.50	$41.30	1.271	281.1	310.0	1.98%	0.0251	0.2133	0.54%
3	Dominion Resources	41.5%	$26,923	$11,173	45.0%	$35,800	$16,110	7.6%	$65.00	$50.00	$57.50	$27.00	2.130	599.0	595.0	-0.13%	(0.0029)	0.5304	-0.15%
4	DPL, Inc.	46.9%	$2,346	$1,100	52.5%	$2,850	$1,496	6.3%	$45.00	$30.00	$37.50	$12.00	3.125	119.0	125.0	0.99%	0.0311	0.6800	2.11%
5	Exelon Corp.	52.4%	$24,112	$12,635	55.0%	$29,200	$16,060	4.9%	$60.00	$45.00	$52.50	$25.00	2.100	660.0	640.0	-0.61%	(0.0129)	0.5238	-0.67%
6	NextEra Energy, Inc.	44.3%	$29,267	$12,965	48.0%	$42,000	$20,160	9.2%	$80.00	$60.00	$70.00	$45.25	1.547	413.6	446.0	1.52%	0.0235	0.3536	0.83%
8	Pepco Holdings	46.2%	$9,203	$4,252	48.0%	$10,600	$5,088	3.7%	$25.00	$16.00	$20.50	$21.25	0.965	222.3	240.0	1.55%	0.0149	(0.0366)	-0.05%
7	PPL Corp.	42.5%	$12,940	$5,500	53.5%	$23,300	$12,466	17.8%	$45.00	$30.00	$37.50	$22.00	1.705	377.2	565.0	8.42%	0.1435	0.4133	5.93%
9	Pub Sv Enterprise Grp	53.2%	$16,513	$8,785	60.0%	$21,800	$13,080	8.3%	$45.00	$35.00	$40.00	$26.00	1.538	506.0	506.0	0.00%	0.0000	0.3500	0.00%
10	UIL Holdings	46.0%	$1,248	$574	40.0%	$3,300	$1,320	18.1%	$40.00	$30.00	$35.00	$26.00	1.346	30.0	50.0	10.77%	0.1450	0.2571	3.73%

(a) The Value Line Investment Survey (Sep. 24 & Nov. 26, 2010).
(b) Computed as (EPS - DPS) / EPS.
(c) Average of values for 2010, 2011, and 2013-15.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2010, 2011, and 2013-15 and Adjustment Factor.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2013-15 BVPS.
(i) Product of change in common shares outstanding and M/B Ratio.
(j) Computed as 1 - B/M Ratio.

FERC DCF MODEL

RATINGS SCREEN PROXY GROUP

		(a)		(b)		(c)	(d)	(e)		(f)	
		6 Mo.Div. Yield		**Adjusted Div. Yield**		**Growth Rates**		**Implied Cost of Equity**			
	Company	**Low**	**High**	**Low**	**High**	**br + sv**	**IBES**	**Low**		**High**	**Average**
1	American Elec Pwr	4.7%	5.0%	4.7%	5.1%	4.5%	3.9%	8.6%	--	9.6%	9.1%
2	Exelon Corp.	4.9%	5.4%	4.8%	5.6%	7.1%	-2.4%	2.4%	--	12.6%	--
3	Pepco Holdings	5.9%	6.4%	5.9%	6.6%	0.7%	7.0%	6.5%	--	13.6%	--
4	PPL Corp.	5.1%	5.5%	5.2%	5.8%	10.6%	3.6%	8.8%	--	16.4%	12.6%
5	Pub Sv Enterprise Grp	4.0%	4.4%	4.1%	4.6%	8.3%	2.0%	6.1%	--	12.9%	--
6	UIL Holdings	6.1%	6.6%	6.2%	6.8%	5.7%	3.7%	9.9%	--	12.5%	11.2%
	Range of Reasonableness							**2.4%**	--	**16.4%**	
	Adjusted Range of Reasonableness (g)							**8.6%**	--	**16.4%**	
	Midpoint							**12.5%**			
	Median (f)										**11.2%**

(a) Six-month average dividend yield for June - November 2010.
(b) Six-month dividend yield adjusted for one-half years' growth.
(c) See Exhibit No. NPT-606.
(d) *Thompson Reuters Company in Context Report* (Dec. 7, 2010).
(e) Excludes highlighted values.
(f) Based on the average of the low and high DCF estimates for all companies with two valid observations.

NON-UTILITY PROXY GROUP

Exhibit No. NPT-608
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DCF MODEL

		(a)	(b)	(c)	(d)		(d)	
		Dividend	**Growth Rates**		**Implied Cost of Equity**			
	Company	**Yield**	**IBES**	**br+sv**	**Low**		**High**	**Average**
1	3M Company	2.32%	12.0%	16.0%	14.3%	--	18.3%	--
2	Abbott Labs.	3.33%	9.3%	15.2%	12.6%	--	18.6%	--
3	Alberto-Culver	0.99%	9.4%	8.1%	9.1%	--	10.4%	9.7%
4	AT&T Inc.	6.03%	6.2%	4.6%	10.6%	--	12.2%	11.4%
5	Automatic Data Proc.	3.12%	10.5%	10.1%	13.3%	--	13.6%	13.4%
6	Bard (C.R.)	0.85%	10.9%	17.6%	11.8%	--	18.5%	--
7	Baxter Int'l Inc.	2.43%	9.2%	17.6%	11.6%	--	20.0%	--
8	Becton, Dickinson	1.92%	8.9%	13.5%	10.8%	--	15.4%	13.1%
9	Bristol-Myers Squibb	4.72%	2.0%	6.3%	6.7%	--	11.0%	--
10	Brown-Forman 'B'	1.97%	10.8%	12.8%	12.8%	--	14.8%	13.8%
11	Chubb Corp.	2.54%	9.3%	7.9%	10.5%	--	11.8%	11.2%
12	Church & Dwight	1.00%	12.0%	11.4%	12.4%	--	13.0%	12.7%
13	Coca-Cola	2.96%	8.5%	10.1%	11.5%	--	13.1%	12.3%
14	Colgate-Palmolive	2.89%	9.1%	30.6%	12.0%	--	33.5%	--
15	Commerce Bancshs.	2.60%	10.0%	7.4%	10.0%	--	12.6%	11.3%
16	ConAgra Foods	4.02%	8.2%	8.0%	12.1%	--	12.2%	12.1%
17	Costco Wholesale	1.35%	12.8%	8.1%	9.4%	--	14.2%	11.8%
18	Cullen/Frost Bankers	3.45%	8.8%	5.5%	8.9%	--	12.3%	10.6%
19	CVS Caremark Corp.	1.12%	11.9%	7.8%	9.0%	--	13.0%	11.0%
20	Ecolab Inc.	1.26%	13.3%	20.0%	14.6%	--	21.2%	--
21	Everest Re Group Ltd.	2.28%	7.5%	7.1%	9.4%	--	9.8%	9.6%
22	Exxon Mobil Corp.	2.65%	11.4%	13.9%	14.1%	--	16.6%	15.3%
23	Gen'l Mills	3.02%	7.1%	10.9%	10.1%	--	13.9%	12.0%
24	Heinz (H.J.)	3.77%	7.3%	16.8%	11.1%	--	20.5%	--
25	Hormel Foods	1.94%	10.0%	11.4%	11.9%	--	13.3%	12.6%
26	Int'l Business Mach.	1.93%	12.9%	29.5%	14.8%	--	31.4%	--
27	Johnson & Johnson	3.45%	6.3%	10.6%	9.8%	--	14.1%	11.9%
28	Kellogg	3.26%	9.2%	17.1%	12.5%	--	20.4%	--
29	Kimberly-Clark	3.95%	8.3%	15.0%	12.3%	--	18.9%	--
30	Kraft Foods	3.65%	8.2%	9.6%	11.9%	--	13.3%	12.6%
31	Lilly (Eli)	5.52%	-6.2%	18.6%	-0.7%	--	24.1%	--
32	Lockheed Martin	4.18%	8.1%	23.2%	12.3%	--	27.4%	--
33	McCormick & Co.	2.42%	9.3%	14.6%	11.7%	--	17.0%	14.4%
34	McDonald's Corp.	3.11%	10.2%	11.8%	13.3%	--	14.9%	14.1%
35	McKesson Corp.	1.17%	10.8%	13.1%	12.0%	--	14.3%	13.1%
36	Medtronic, Inc.	2.59%	9.2%	14.2%	11.8%	--	16.8%	14.3%
37	Microsoft Corp.	2.52%	10.3%	20.9%	12.8%	--	23.4%	--
38	NIKE, Inc. 'B'	1.36%	12.0%	14.1%	13.4%	--	15.5%	14.4%
39	Northrop Grumman	3.14%	11.0%	6.4%	9.6%	--	14.1%	11.9%
40	PepsiCo, Inc.	3.01%	8.9%	14.9%	11.9%	--	17.9%	--
41	Pfizer, Inc.	4.42%	2.5%	4.9%	6.9%	--	9.4%	--
42	Procter & Gamble	3.09%	8.8%	6.4%	9.5%	--	11.9%	10.7%
43	Raytheon Co.	3.24%	7.3%	8.0%	10.5%	--	11.3%	10.9%
44	Stryker Corp.	1.17%	10.5%	14.2%	11.7%	--	15.4%	13.5%
45	Sysco Corp.	3.41%	10.5%	14.1%	13.9%	--	17.5%	15.7%
46	TJX Companies	1.34%	13.8%	18.6%	15.1%	--	20.0%	--
47	United Parcel Serv.	2.70%	12.8%	19.1%	15.5%	--	21.8%	--
48	Verizon Communic.	6.00%	6.9%	2.8%	8.8%	--	12.9%	10.9%
49	Walgreen Co.	2.05%	13.3%	9.1%	11.2%	--	15.4%	13.3%
50	Wal-Mart Stores	2.35%	10.1%	7.4%	9.7%	--	12.5%	11.1%
51	Waste Management	3.51%	12.0%	4.6%	8.1%	--	15.5%	11.8%
	Range of Reasonableness				**-0.7%**	--	**33.5%**	
	Adjusted Range of Reasonableness (e)				**8.1%**	--	**17.5%**	
	Midpoint				**12.8%**			
	Median (f)							**12.1%**

(a) www.valueline.com (retrieved Oct. 29, 2010).
(b) *Thomson Reuters Company in Context Report* (Oct. 29, 2010).
(c) See Exhibit No. NPT-609.
(d) Sum of dividend yield and respective growth rate.
(e) Excludes highlighted figures.
(f) Based on the average of the low and high DCF estimates for all companies with two valid observations.

BR + SV GROWTH RATE

Exhibit No. NPT-609
Page 1 of 2

NON-UTILITY PROXY GROUP

		(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(a)	(a)	(b)	(a)	(c)	(c)	(d)	(e)		
		2010				2011				2014						Adjust.		Avg	Avg
	Company	EPS	DPS	b	r	EPS	DPS	b	r	EPS	DPS	b	r	Avg b	Avg r	Factor	Adj. r	br	br + sv
1	3M Company	$5.75	$2.10	63.5%	26.5%	$5.90	$2.26	61.7%	24.0%	$7.55	$3.04	59.7%	21.5%	61.6%	24.0%	1.0586	25.4%	15.7%	**16.0%**
2	Abbott Labs.	$4.15	$1.76	57.6%	27.5%	$4.70	$1.92	59.1%	28.0%	$5.70	$2.18	61.8%	26.0%	59.5%	27.2%	1.0384	28.2%	16.8%	**15.2%**
3	Alberto-Culver	$1.55	$0.33	78.7%	11.5%	$1.75	$0.37	78.9%	12.5%	$2.35	$0.55	76.6%	13.5%	78.1%	12.5%	1.0315	12.9%	10.1%	**8.1%**
4	AT&T Inc.	$2.33	$1.68	27.9%	13.5%	$2.50	$1.72	31.2%	13.5%	$3.25	$2.00	38.5%	14.5%	32.5%	13.8%	1.0253	14.2%	4.6%	**4.6%**
5	Automatic Data Proc.	$2.37	$1.34	43.5%	22.0%	$2.45	$1.38	43.7%	18.5%	$3.45	$1.60	53.6%	15.0%	46.9%	18.5%	1.0786	20.0%	9.4%	**10.1%**
6	Bard (C.R.)	$5.50	$0.70	87.3%	23.5%	$6.20	$0.74	88.1%	25.0%	$7.75	$0.85	89.0%	24.5%	88.1%	24.3%	1.0255	25.0%	22.0%	**17.6%**
7	Baxter Int'l Inc.	$3.95	$1.20	69.6%	33.0%	$4.25	$1.35	68.2%	32.0%	$5.85	$1.75	70.1%	27.0%	69.3%	30.7%	1.0524	32.3%	22.4%	**17.6%**
8	Becton, Dickinson	$5.12	$1.48	71.1%	22.5%	$5.60	$1.64	70.7%	22.0%	$7.60	$2.20	71.1%	21.0%	71.0%	21.8%	1.0481	22.9%	16.2%	**13.5%**
9	Bristol-Myers Squibb	$2.00	$1.28	36.0%	21.5%	$2.10	$1.32	37.1%	21.0%	$2.35	$1.54	34.5%	20.0%	35.9%	20.8%	1.0263	21.4%	7.7%	**6.3%**
10	Brown-Forman 'B'	$3.30	$1.20	63.6%	24.0%	$3.50	$1.24	64.6%	22.0%	$4.35	$1.40	67.8%	19.0%	65.3%	21.7%	1.0523	22.8%	14.9%	**12.8%**
11	Chubb Corp.	$5.30	$1.46	72.5%	10.5%	$5.60	$1.50	73.2%	10.5%	$7.00	$1.60	77.1%	12.0%	74.3%	11.0%	1.0184	11.2%	8.3%	**7.9%**
12	Church & Dwight	$3.97	$0.56	85.9%	15.5%	$4.45	$0.56	87.4%	15.0%	$5.80	$0.64	89.0%	15.0%	87.4%	15.2%	1.0474	15.9%	13.9%	**11.4%**
13	Coca-Cola	$3.35	$1.76	47.5%	29.5%	$3.75	$1.88	49.9%	28.0%	$4.95	$2.48	49.9%	27.0%	49.1%	28.2%	1.0479	29.5%	14.5%	**10.1%**
14	Colgate-Palmolive	$4.80	$2.03	57.7%	81.5%	$5.25	$2.24	57.3%	72.0%	$7.50	$3.20	57.3%	41.0%	57.5%	64.8%	1.0984	71.2%	40.9%	**30.6%**
15	Commerce Bancshs.	$2.55	$0.94	63.1%	10.5%	$2.65	$0.96	63.8%	10.5%	$3.50	$1.20	65.7%	10.5%	64.2%	10.5%	1.0421	10.9%	7.0%	**7.4%**
16	ConAgra Foods	$1.74	$0.79	54.6%	15.8%	$1.80	$0.86	52.2%	15.0%	$2.35	$1.00	57.4%	15.5%	54.8%	15.4%	1.0330	15.9%	8.7%	**8.0%**
17	Costco Wholesale	$2.90	$0.82	71.7%	12.0%	$3.30	$0.86	73.9%	12.5%	$4.20	$0.95	77.4%	13.0%	74.3%	12.5%	1.0296	12.9%	9.6%	**8.1%**
18	Cullen/Frost Bankers	$3.40	$1.78	47.6%	10.0%	$3.60	$1.83	49.2%	10.0%	$4.35	$2.10	51.7%	10.0%	49.5%	10.0%	1.0373	10.4%	5.1%	**5.5%**
19	CVS Caremark Corp.	$2.72	$0.35	87.1%	10.0%	$3.00	$0.40	86.7%	10.0%	$4.05	$0.56	86.2%	11.0%	86.7%	10.3%	1.0284	10.6%	9.2%	**7.8%**
20	Ecolab Inc.	$2.25	$0.62	72.4%	24.0%	$2.55	$0.66	74.1%	23.5%	$3.60	$0.85	76.4%	25.5%	74.3%	24.3%	1.0530	25.6%	19.0%	**20.0%**
21	Everest Re Group Ltd.	$8.25	$1.96	76.2%	7.0%	$10.25	$2.00	80.5%	8.0%	$14.00	$2.35	83.2%	8.5%	80.0%	7.8%	1.0335	8.1%	6.5%	**7.1%**
22	Exxon Mobil Corp.	$5.90	$1.74	70.5%	20.5%	$6.50	$1.82	72.0%	21.0%	$9.35	$2.05	78.1%	22.5%	73.5%	21.3%	1.0477	22.4%	16.4%	**13.9%**
23	Gen'l Mills	$2.30	$0.96	58.3%	29.1%	$2.45	$1.12	54.3%	29.5%	$3.10	$1.36	56.1%	27.5%	56.2%	28.7%	1.0310	29.6%	16.6%	**10.9%**
24	Heinz (H.J.)	$3.05	$1.80	41.0%	40.0%	$3.35	$1.92	42.7%	36.0%	$4.10	$2.32	43.4%	30.5%	42.4%	35.5%	1.0838	38.5%	16.3%	**16.8%**
25	Hormel Foods	$2.90	$0.84	71.0%	16.0%	$3.05	$0.88	71.1%	15.5%	$4.00	$1.20	70.0%	15.0%	70.7%	15.5%	1.0513	16.3%	11.5%	**11.4%**
26	Int'l Business Mach.	$11.25	$2.50	77.8%	57.0%	$12.40	$2.75	77.8%	48.0%	$18.00	$3.60	80.0%	35.5%	78.5%	46.8%	1.0921	51.1%	40.2%	**29.5%**
27	Johnson & Johnson	$4.70	$2.11	55.1%	23.5%	$5.10	$2.30	54.9%	23.0%	$6.70	$2.80	58.2%	21.5%	56.1%	22.7%	1.0495	23.8%	13.3%	**10.6%**
28	Kellogg	$3.45	$1.56	54.8%	54.5%	$3.80	$1.62	57.4%	53.5%	$5.30	$2.00	62.3%	39.5%	58.1%	49.2%	1.0694	52.6%	30.6%	**17.1%**
29	Kimberly-Clark	$4.85	$2.58	46.8%	36.5%	$5.10	$2.64	48.2%	36.5%	$6.25	$2.75	56.0%	40.0%	50.3%	37.7%	1.0140	38.2%	19.2%	**15.0%**
30	Kraft Foods	$2.05	$1.16	43.4%	10.5%	$2.35	$1.16	50.6%	11.5%	$3.00	$1.40	53.3%	12.5%	49.1%	11.5%	1.0480	12.1%	5.9%	**9.6%**
31	Lilly (Eli)	$4.55	$1.96	56.9%	45.5%	$4.45	$1.96	56.0%	37.5%	$3.40	$2.20	35.3%	22.0%	49.4%	35.0%	1.0636	37.2%	18.4%	**18.6%**
32	Lockheed Martin	$7.50	$2.54	66.1%	57.7%	$7.75	$2.70	65.2%	50.7%	$13.25	$3.50	73.6%	39.8%	68.3%	49.4%	1.0954	54.1%	36.9%	**23.2%**
33	McCormick & Co.	$2.60	$1.04	60.0%	22.5%	$2.75	$1.08	60.7%	21.0%	$3.45	$1.32	61.7%	18.5%	60.8%	20.7%	1.0649	22.0%	13.4%	**14.6%**
34	McDonald's Corp.	$4.53	$2.25	50.3%	35.5%	$4.90	$2.45	50.0%	36.5%	$5.90	$3.00	49.2%	31.0%	49.8%	34.3%	1.0303	35.4%	17.6%	**11.8%**
35	McKesson Corp.	$4.85	$0.72	85.2%	17.0%	$5.35	$0.72	86.5%	16.5%	$6.75	$0.72	89.3%	14.5%	87.0%	16.0%	1.0453	16.7%	14.6%	**13.1%**
36	Medtronic, Inc.	$3.50	$0.86	75.4%	22.5%	$3.85	$0.91	76.4%	21.0%	$4.50	$1.18	73.8%	17.5%	75.2%	20.3%	1.0584	21.5%	16.2%	**14.2%**
37	Microsoft Corp.	$2.10	$0.52	75.2%	40.6%	$2.40	$0.56	76.7%	35.5%	$3.35	$0.70	79.1%	31.0%	77.0%	35.7%	1.0763	38.4%	29.6%	**20.9%**
38	NIKE, Inc. 'B'	$3.86	$1.06	72.5%	19.5%	$4.30	$1.14	73.5%	19.0%	$5.40	$1.40	74.1%	16.0%	73.4%	18.2%	1.0664	19.4%	14.2%	**14.1%**
39	Northrop Grumman	$5.75	$1.84	68.0%	13.0%	$6.50	$1.97	69.7%	13.5%	$10.25	$2.50	75.6%	15.5%	71.1%	14.0%	1.0293	14.4%	10.2%	**6.4%**
40	PepsiCo, Inc.	$4.10	$1.86	54.6%	30.0%	$4.60	$1.96	57.4%	30.5%	$6.75	$2.34	65.3%	28.0%	59.1%	29.5%	1.0738	31.7%	18.7%	**14.9%**
41	Pfizer, Inc.	$1.15	$0.72	37.4%	10.0%	$1.40	$0.80	42.9%	11.0%	$2.05	$1.16	43.4%	14.0%	41.2%	11.7%	1.0287	12.0%	4.9%	**4.9%**
42	Procter & Gamble	$3.53	$1.80	49.0%	17.8%	$3.95	$1.95	50.6%	18.5%	$5.20	$2.18	58.1%	19.0%	52.6%	18.4%	1.0214	18.8%	9.9%	**6.4%**
43	Raytheon Co.	$4.25	$1.50	64.7%	16.6%	$5.35	$1.60	70.1%	19.0%	$7.00	$2.00	71.4%	19.0%	68.7%	18.2%	1.0245	18.6%	12.8%	**8.0%**
44	Stryker Corp.	$3.25	$0.60	81.5%	17.5%	$3.65	$0.64	82.5%	17.5%	$5.35	$0.84	84.3%	16.5%	82.8%	17.2%	1.0662	18.3%	15.1%	**14.2%**
45	Sysco Corp.	$1.99	$0.99	50.3%	30.9%	$2.10	$1.00	52.4%	30.0%	$2.75	$1.00	63.6%	25.5%	55.4%	28.8%	1.0484	30.2%	16.7%	**14.1%**
46	TJX Companies	$3.40	$0.60	82.4%	50.0%	$3.80	$0.66	82.6%	49.0%	$4.80	$0.80	83.3%	41.0%	82.8%	46.7%	1.0374	48.4%	40.1%	**18.6%**
47	United Parcel Serv.	$3.40	$1.88	44.7%	39.0%	$4.10	$2.05	50.0%	38.0%	$5.75	$2.40	58.3%	30.0%	51.0%	35.7%	1.0917	38.9%	19.9%	**19.1%**
48	Verizon Communic.	$2.25	$1.90	15.6%	12.0%	$2.30	$1.90	17.4%	12.5%	$3.05	$1.96	35.7%	14.5%	22.9%	13.0%	1.0250	13.3%	3.1%	**2.8%**
49	Walgreen Co.	$2.11	$0.55	73.9%	14.0%	$2.40	$0.70	70.8%	14.5%	$3.35	$0.94	71.9%	15.0%	72.2%	14.5%	1.0379	15.0%	10.9%	**9.1%**
50	Wal-Mart Stores	$4.05	$1.21	70.1%	17.5%	$4.45	$1.38	69.0%	17.5%	$6.05	$1.75	71.1%	20.0%	70.1%	18.3%	1.0336	18.9%	13.3%	**7.4%**
51	Waste Management	$2.10	$1.26	40.0%	16.0%	$2.35	$1.32	43.8%	17.5%	$3.15	$1.60	49.2%	20.0%	44.3%	17.8%	1.0136	18.1%	8.0%	**4.6%**

BR + SV GROWTH RATE

NON-UTILITY PROXY GROUP

		(a)	(a)	(g)	(a)	(a)		(a)	(h)	(a)	(a)	(g)	(i)	(j)	
		-------- Common Equity --------			---------- 2014 Price ----------			2014		-------- No. Shares --------			---------- "sv" Factor ----------		
	Company	2009	2014	Chg.	High	Low	Avg.	BVPS	M/B	2009	2014	Chg.	s	v	sv
1	3M Company	$12,764	$22,945	12.4%	$135.00	$110.00	$122.50	$32.10	3.816	710.6	715.0	0.12%	0.0047	0.7380	0.35%
2	Abbott Labs.	$22,856	$33,550	8.0%	$115.00	$95.00	$105.00	$22.05	4.762	1,551.9	1,520.0	-0.41%	(0.0197)	0.7900	-1.56%
3	Alberto-Culver	$1,197	$1,640	6.5%	$50.00	$40.00	$45.00	$17.85	2.521	98.3	92.0	-1.31%	(0.0330)	0.6033	-1.99%
4	AT&T Inc.	$102,339	$131,865	5.2%	$50.00	$40.00	$45.00	$22.35	2.013	5,901.9	5,900.0	-0.01%	(0.0001)	0.5033	-0.01%
5	Automatic Data Proc.	$5,323	$11,700	17.1%	$85.00	$70.00	$77.50	$22.95	3.377	501.7	510.0	0.33%	0.0111	0.7039	0.78%
6	Bard (C.R.)	$2,194	$2,830	5.2%	$155.00	$125.00	$140.00	$31.45	4.452	95.9	90.0	-1.27%	(0.0564)	0.7754	-4.37%
7	Baxter Int'l Inc.	$7,191	$12,150	11.1%	$90.00	$75.00	$82.50	$22.10	3.733	601.0	550.0	-1.76%	(0.0656)	0.7321	-4.80%
8	Becton, Dickinson	$5,143	$8,325	10.1%	$135.00	$110.00	$122.50	$37.30	3.284	237.1	223.0	-1.22%	(0.0400)	0.6955	-2.78%
9	Bristol-Myers Squibb	$14,785	$19,230	5.4%	$40.00	$30.00	$35.00	$11.65	3.004	1,709.5	1,650.0	-0.71%	(0.0212)	0.6671	-1.42%
10	Brown-Forman 'B'	$1,895	$3,200	11.0%	$80.00	$65.00	$72.50	$22.85	3.173	147.0	140.0	-0.97%	(0.0306)	0.6848	-2.10%
11	Chubb Corp.	$15,634	$18,800	3.8%	$85.00	$70.00	$77.50	$60.65	1.278	332.0	310.0	-1.36%	(0.0174)	0.2174	-0.38%
12	Church & Dwight	$1,602	$2,575	10.0%	$110.00	$90.00	$100.00	$39.60	2.525	70.6	65.0	-1.63%	(0.0410)	0.6040	-2.48%
13	Coca-Cola	$24,799	$40,035	10.1%	$115.00	$95.00	$105.00	$18.20	5.769	2,303.0	2,200.0	-0.91%	(0.0526)	0.8267	-4.34%
14	Colgate-Palmolive	$3,116	$8,360	21.8%	$165.00	$135.00	$150.00	$18.15	8.264	494.2	460.0	-1.42%	(0.1176)	0.8790	-10.34%
15	Commerce Bancshs.	$1,886	$2,875	8.8%	$50.00	$40.00	$45.00	$33.05	1.362	83.1	87.0	0.92%	0.0125	0.2656	0.33%
16	ConAgra Foods	$4,721	$6,565	6.8%	$40.00	$30.00	$35.00	$15.25	2.295	441.7	430.0	-0.53%	(0.0122)	0.5643	-0.69%
17	Costco Wholesale	$10,018	$13,470	6.1%	$90.00	$75.00	$82.50	$32.45	2.542	436.0	415.0	-0.98%	(0.0249)	0.6067	-1.51%
18	Cullen/Frost Bankers	$1,894	$2,750	7.7%	$65.00	$55.00	$60.00	$43.65	1.375	60.0	63.0	0.97%	0.0133	0.2725	0.36%
19	CVS Caremark Corp.	$35,768	$47,500	5.8%	$65.00	$55.00	$60.00	$38.80	1.546	1,391.0	1,225.0	-2.51%	(0.0388)	0.3533	-1.37%
20	Ecolab Inc.	$2,001	$3,400	11.2%	$65.00	$55.00	$60.00	$14.15	4.240	236.6	240.0	0.29%	0.0121	0.7642	0.93%
21	Everest Re Group Ltd.	$6,102	$8,530	6.9%	$155.00	$125.00	$140.00	$170.55	0.821	59.3	50.0	-3.35%	(0.0275)	(0.2182)	0.60%
22	Exxon Mobil Corp.	$110,569	$178,200	10.0%	$125.00	$100.00	$112.50	$40.50	2.778	4,727.0	4,400.0	-1.42%	(0.0395)	0.6400	-2.53%
23	Gen'l Mills	$5,175	$7,055	6.4%	$55.00	$45.00	$50.00	$11.75	4.255	656.0	600.0	-1.77%	(0.0753)	0.7650	-5.76%
24	Heinz (H.J.)	$1,891	$4,380	18.3%	$75.00	$60.00	$67.50	$13.70	4.927	318.1	320.0	0.12%	0.0060	0.7970	0.48%
25	Hormel Foods	$2,124	$3,550	10.8%	$80.00	$65.00	$72.50	$26.70	2.715	133.6	133.0	-0.09%	(0.0024)	0.6317	-0.15%
26	Int'l Business Mach.	$22,755	$57,300	20.3%	$240.00	$195.00	$217.50	$52.10	4.175	1,305.3	1,100.0	-3.36%	(0.1405)	0.7605	-10.68%
27	Johnson & Johnson	$50,588	$83,000	10.4%	$120.00	$95.00	$107.50	$31.90	3.370	2,754.3	2,600.0	-1.15%	(0.0386)	0.7033	-2.72%
28	Kellogg	$2,272	$4,555	14.9%	$95.00	$75.00	$85.00	$13.60	6.250	381.4	335.0	-2.56%	(0.1600)	0.8400	-13.44%
29	Kimberly-Clark	$5,406	$6,220	2.8%	$105.00	$85.00	$95.00	$15.55	6.109	417.0	400.0	-0.83%	(0.0506)	0.8363	-4.24%
30	Kraft Foods	$25,972	$42,000	10.1%	$55.00	$45.00	$50.00	$24.00	2.083	1,477.9	1,750.0	3.44%	0.0716	0.5200	3.72%
31	Lilly (Eli)	$9,524	$18,000	13.6%	$50.00	$45.00	$47.50	$15.60	3.045	1,149.0	1,155.0	0.10%	0.0032	0.6716	0.21%
32	Lockheed Martin	$4,129	$10,750	21.1%	$205.00	$165.00	$185.00	$33.30	5.556	372.9	320.0	-3.01%	(0.1674)	0.8200	-13.73%
33	McCormick & Co.	$1,335	$2,555	13.9%	$75.00	$60.00	$67.50	$18.95	3.562	131.8	135.0	0.48%	0.0171	0.7193	1.23%
34	McDonald's Corp.	$14,034	$19,000	6.2%	$105.00	$85.00	$95.00	$19.00	5.000	1,076.7	1,000.0	-1.47%	(0.0734)	0.8000	-5.87%
35	McKesson Corp.	$7,532	$11,855	9.5%	$100.00	$80.00	$90.00	$47.40	1.899	271.0	250.0	-1.60%	(0.0304)	0.4733	-1.44%
36	Medtronic, Inc.	$14,629	$26,250	12.4%	$70.00	$55.00	$62.50	$25.60	2.441	1,097.3	1,025.0	-1.35%	(0.0331)	0.5904	-1.95%
37	Microsoft Corp.	$39,558	$85,000	16.5%	$55.00	$45.00	$50.00	$10.75	4.651	8,908.0	7,900.0	-2.37%	(0.1104)	0.7850	-8.66%
38	NIKE, Inc. 'B'	$8,693	$16,900	14.2%	$95.00	$80.00	$87.50	$34.90	2.507	485.5	484.0	-0.06%	(0.0016)	0.6011	-0.09%
39	Northrop Grumman	$12,687	$17,000	6.0%	$145.00	$120.00	$132.50	$68.00	1.949	306.9	250.0	-4.02%	(0.0783)	0.4868	-3.81%
40	PepsiCo, Inc.	$17,442	$36,550	15.9%	$150.00	$120.00	$135.00	$24.40	5.533	1,565.0	1,500.0	-0.84%	(0.0467)	0.8193	-3.83%
41	Pfizer, Inc.	$90,014	$120,000	5.9%	$30.00	$25.00	$27.50	$14.85	1.852	8,070.0	8,070.0	0.00%	-	0.4600	0.00%
42	Procter & Gamble	$63,099	$78,135	4.4%	$105.00	$85.00	$95.00	$28.95	3.282	2,917.0	2,700.0	-1.53%	(0.0503)	0.6953	-3.50%
43	Raytheon Co.	$9,827	$12,550	5.0%	$110.00	$90.00	$100.00	$38.00	2.632	383.2	330.0	-2.95%	(0.0775)	0.6200	-4.81%
44	Stryker Corp.	$6,595	$12,795	14.2%	$130.00	$105.00	$117.50	$32.75	3.588	397.9	391.0	-0.35%	(0.0125)	0.7213	-0.90%
45	Sysco Corp.	$3,828	$6,210	10.2%	$50.00	$40.00	$45.00	$11.00	4.091	590.0	565.0	-0.86%	(0.0353)	0.7556	-2.67%
46	TJX Companies	$2,889	$4,200	7.8%	$85.00	$70.00	$77.50	$12.75	6.078	409.4	330.0	-4.22%	(0.2565)	0.8355	-21.43%
47	United Parcel Serv.	$7,630	$19,145	20.2%	$125.00	$105.00	$115.00	$19.45	5.913	992.9	985.0	-0.16%	(0.0094)	0.8309	-0.78%
48	Verizon Communic.	$41,600	$53,439	5.1%	$60.00	$50.00	$55.00	$18.95	2.902	2,835.7	2,820.0	-0.11%	(0.0032)	0.6555	-0.21%
49	Walgreen Co.	$14,376	$21,000	7.9%	$60.00	$50.00	$55.00	$22.60	2.434	988.6	930.0	-1.21%	(0.0295)	0.5891	-1.74%
50	Wal-Mart Stores	$70,749	$98,980	6.9%	$100.00	$80.00	$90.00	$30.45	2.956	3,786.0	3,250.0	-3.01%	(0.0889)	0.6617	-5.88%
51	Waste Management	$6,285	$7,200	2.8%	$50.00	$45.00	$47.50	$16.20	2.932	486.1	445.0	-1.75%	(0.0514)	0.6589	-3.39%

(a) www.valueline.com (retrieved Oct. 29, 2010).
(b) Computed as (EPS - DPS) / EPS.
(c) Average of values for 2010, 2011, and 2013-15.
(d) Computed using the formula 2*(1+5-Yr. Change in Equity)/(2+5 Yr. Change in Equity).
(e) Product of average year-end "r" for 2010, 2011, and 2013-15 and Adjustment Factor.
(f) Product of total capital and equity ratio.
(g) Five-year rate of change.
(h) Average of High and Low expected market prices divided by 2013-15 BVPS.
(i) Product of change in common shares outstanding and M/B Ratio.
(j) Computed as 1 - B/M Ratio.

CAPITAL ASSET PRICING MODEL

NATIONAL PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
			S&P 500					
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Beta**	**Implied Cost of Equity**
1	Ameren Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
2	American Elec Pwr	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
3	Avista Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
4	Black Hills Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
5	CenterPoint Energy	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
6	Cleco Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
7	CMS Energy	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
8	DTE Energy Co.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
9	Edison International	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
10	Great Plains Energy	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
11	Hawaiian Elec.	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
12	IDACORP, Inc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
13	Integrys Energy Grp	2.5%	10.6%	13.0%	4.0%	9.0%	0.90	12.1%
14	ITC Holdings Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
15	Pepco Holdings	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
16	PG&E Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.55	9.0%
17	Pinnacle West Capital	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
18	Portland General Elec.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
19	PPL Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
20	Progress Energy	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
21	TECO Energy	2.5%	10.6%	13.0%	4.0%	9.0%	0.85	11.7%
22	UIL Holdings	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
23	Westar Energy	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
24	Wisconsin Energy	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
	Range of Reasonableness							**9.0% -- 12.1%**
	Midpoint							**10.5%**
	Median							**10.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Nov. 5, 2010)
(b) http://finance.yahoo.com (retrieved Nov. 10, 2010).
(c) (a) + (b).
(d) Six-month average yield on 30-year Treasury bonds at November 2010 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) See Exhibit No. NPT-602, page 1.
(g) (d) + (e) x (f).

CAPITAL ASSET PRICING MODEL

REGIONAL PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
			S&P 500					
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Beta**	**Implied Cost of Equity**
1	American Elec Pwr	2.5%	10.6%	13.1%	4.0%	9.1%	0.70	10.4%
2	Consolidated Edison	2.5%	10.6%	13.1%	4.0%	9.1%	0.65	9.9%
3	Dominion Resources	2.5%	10.6%	13.1%	4.0%	9.1%	0.70	10.4%
4	DPL, Inc.	2.5%	10.6%	13.1%	4.0%	9.1%	0.60	9.5%
5	Exelon Corp.	2.5%	10.6%	13.1%	4.0%	9.1%	0.85	11.7%
6	NextEra Energy	2.5%	10.6%	13.1%	4.0%	9.1%	0.75	10.8%
7	PPL Corp.	2.5%	10.6%	13.1%	4.0%	9.1%	0.80	11.3%
8	Pepco Holdings	2.5%	10.6%	13.1%	4.0%	9.1%	0.70	10.4%
9	Pub Sv Enterprise Grp	2.5%	10.6%	13.1%	4.0%	9.1%	0.80	11.3%
10	UIL Holdings	2.5%	10.6%	13.1%	4.0%	9.1%	0.70	10.4%
	Range of Reasonableness							**9.5% -- 11.7%**
	Midpoint							**10.6%**
	Median							**10.4%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Nov. 5, 2010).
(b) http://finance.yahoo.com (retrieved Nov. 10, 2010).
(c) (a) + (b).
(d) Six-month average yield on 30-year Treasury bonds at November 2010 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) See Exhibit No. NPT-602, page 2.
(g) (d) + (e) x (f).

CAPITAL ASSET PRICING MODEL

RATINGS SCREEN PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
			S&P 500					
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Beta**	**Implied Cost of Equity**
1	American Elec Pwr	2.5%	10.6%	13.1%	4.0%	9.1%	0.70	10.4%
2	Exelon Corp.	2.5%	10.6%	13.1%	4.0%	9.1%	0.85	11.7%
3	PPL Corp.	2.5%	10.6%	13.1%	4.0%	9.1%	0.80	11.3%
4	Pepco Holdings	2.5%	10.6%	13.1%	4.0%	9.1%	0.70	10.4%
5	Pub Sv Enterprise Grp	2.5%	10.6%	13.1%	4.0%	9.1%	0.80	11.3%
6	UIL Holdings	2.5%	10.6%	13.1%	4.0%	9.1%	0.70	10.4%
	Range of Reasonableness							**10.4% -- 11.7%**
	Midpoint							**11.1%**
	Median							**10.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Nov. 5, 2010).
(b) http://finance.yahoo.com (retrieved Nov. 10, 2010).
(c) (a) + (b).
(d) Six-month average yield on 30-year Treasury bonds at November 2010 from the Federal Reserve Board at http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) See Exhibit No. NPT-602, page 3.
(g) (d) + (e) x (f).

CAPITAL ASSET PRICING MODEL

NON-UTILITY PROXY GROUP

		(a)	(b)	(c)	(d)	(e)	(f)	(g)
			S&P 500					
	Company	**Div Yield**	**Proj. Growth**	**Cost of Equity**	**Risk-Free Rate**	**Risk Premium**	**Beta**	**Implied Cost of Equity**
1	3M Company	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
2	Abbott Labs.	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
3	Alberto-Culver	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
4	AT&T Inc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
5	Automatic Data Proc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
6	Bard (C.R.)	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
7	Baxter Int'l Inc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
8	Becton, Dickinson	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
9	Bristol-Myers Squibb	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
10	Brown-Forman 'B'	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
11	Chubb Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.85	11.7%
12	Church & Dwight	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
13	Coca-Cola	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
14	Colgate-Palmolive	2.5%	10.6%	13.0%	4.0%	9.0%	0.55	9.0%
15	Commerce Bancshs.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
16	ConAgra Foods	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
17	Costco Wholesale	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
18	Cullen/Frost Bankers	2.5%	10.6%	13.0%	4.0%	9.0%	0.85	11.7%
19	CVS Caremark Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
20	Ecolab Inc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
21	Everest Re Group Ltd.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
22	Exxon Mobil Corp	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
23	Gen'l Mills	2.5%	10.6%	13.0%	4.0%	9.0%	0.50	8.5%
24	Heinz (H.J.)	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
25	Hormel Foods	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
26	Int'l Business Mach.	2.5%	10.6%	13.0%	4.0%	9.0%	0.85	11.7%
27	Johnson & Johnson	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
28	Kellogg	2.5%	10.6%	13.0%	4.0%	9.0%	0.55	9.0%
29	Kimberly-Clark	2.5%	10.6%	13.0%	4.0%	9.0%	0.55	9.0%
30	Kraft Foods	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
31	Lilly (Eli)	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
32	Lockheed Martin	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
33	McCormick & Co.	2.5%	10.6%	13.0%	4.0%	9.0%	0.55	9.0%
34	McDonald's Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.65	9.9%
35	McKesson Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
36	Medtronic, Inc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
37	Microsoft Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
38	NIKE, Inc. 'B'	2.5%	10.6%	13.0%	4.0%	9.0%	0.85	11.7%
39	Northrop Grumman	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
40	PepsiCo, Inc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
41	Pfizer, Inc.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
42	Procter & Gamble	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
43	Raytheon Co.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
44	Stryker Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
45	Sysco Corp.	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
46	TJX Companies	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
47	United Parcel Serv.	2.5%	10.6%	13.0%	4.0%	9.0%	0.85	11.7%
48	Verizon Communic	2.5%	10.6%	13.0%	4.0%	9.0%	0.70	10.3%
49	Walgreen Co.	2.5%	10.6%	13.0%	4.0%	9.0%	0.75	10.8%
50	Wal-Mart Stores	2.5%	10.6%	13.0%	4.0%	9.0%	0.60	9.4%
51	Waste Management	2.5%	10.6%	13.0%	4.0%	9.0%	0.80	11.2%
	Range of Reasonableness							**8.5% -- 11.7%**
	Midpoint							**10.1%**
	Median							**10.8%**

(a) Weighted average dividend yield for the dividend paying firms in the S&P 500 from www.valueline.com (Retreived Nov. 5, 201
(b) http://finance.yahoo.com (retrieved Nov. 10, 2010).
(c) (a) + (b).
(d) Six-month average yield on 30-year Treasury bonds at November 2010 from the Federal Reserve Board a
http://www.federalreserve.gov/releases/h15/data.htm.
(e) (c) - (d).
(f) www.valueline.com (retrieved Oct. 29, 2010)
(g) (d) + (e) x (f).

EXPECTED EARNINGS APPROACH

Exhibit No. NPT-611
Page 1 of 3

NATIONAL PROXY GROUP

		(a)				(b)	(c)
		Return on Equity ("r")				**Adjustment**	**Adjusted Return**
	Company	**2010**	**2011**	**2014**	**Average**	**Factor**	**on Common Equity**
1	Ameren Corp.	7.5%	7.0%	7.0%	7.2%	1.0200	7.3%
2	American Elec Pwr	9.0%	10.5%	10.0%	9.8%	1.0325	10.2%
3	Avista Corp.	8.0%	8.0%	9.0%	8.3%	1.0252	8.5%
4	Black Hills Corp.	5.5%	7.0%	7.5%	6.7%	1.0211	6.8%
5	CenterPoint Energy	13.5%	15.0%	14.5%	14.3%	1.0560	15.1%
6	Cleco Corp.	11.0%	10.5%	10.5%	10.7%	1.0420	11.1%
7	CMS Energy	11.5%	12.0%	12.0%	11.8%	1.0295	12.2%
8	DTE Energy Co.	9.5%	9.5%	9.5%	9.5%	1.0278	9.8%
9	Edison International	10.0%	9.5%	8.5%	9.3%	1.0263	9.6%
10	Great Plains Energy	7.0%	7.0%	7.5%	7.2%	1.0247	7.3%
11	Hawaiian Elec.	8.0%	9.0%	10.5%	9.2%	1.0220	9.4%
12	IDACORP, Inc.	9.5%	9.0%	8.5%	9.0%	1.0303	9.3%
13	Integrys Energy Grp	8.0%	8.5%	9.5%	8.7%	1.0136	8.8%
14	ITC Holdings Corp.	13.0%	14.0%	15.0%	14.0%	1.0467	14.7%
15	Pepco Holdings	5.5%	6.0%	7.5%	6.3%	1.0180	6.4%
16	PG&E Corp.	10.5%	11.5%	12.0%	11.3%	1.0401	11.8%
17	Pinnacle West Capital	9.0%	9.0%	9.0%	9.0%	1.0351	9.3%
18	Portland General Elec.	8.0%	7.0%	8.5%	7.8%	1.0327	8.1%
19	PPL Corp.	11.5%	12.5%	11.5%	11.8%	1.0816	12.8%
20	Progress Energy	8.5%	8.5%	9.0%	8.7%	1.0248	8.9%
21	TECO Energy	12.0%	12.5%	13.0%	12.5%	1.0263	12.8%
22	UIL Holdings	10.0%	9.0%	9.0%	9.3%	1.0831	10.1%
23	Westar Energy	8.5%	8.0%	8.5%	8.3%	1.0281	8.6%
24	Wisconsin Energy	11.5%	12.0%	13.0%	12.2%	1.0313	12.5%
	Range of Reasonableness						**6.4% -- 15.1%**
	Adjusted Range of Reasonableness (d)						**8.1% -- 15.1%**
	Midpoint						**11.6%**
	Median (d)						**9.9%**

(a) The Value Line Investment Survey (Sep. 24, Nov. 5, & Nov. 26, 2010).
(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit No. NPT-604.
(c) (a) x (b).
(d) Excludes highlighted values.

EXPECTED EARNINGS APPROACH

REGIONAL PROXY GROUP

		(a)				(b)	(c)
		Return on Equity ("r")				**Adjustment**	**Adjusted Return**
	Company	**2010**	**2011**	**2014**	**Average**	**Factor**	**on Common Equity**
1	American Elec Pwr	9.0%	10.5%	10.0%	9.8%	1.0325	10.2%
2	Consolidated Edison	9.5%	9.5%	9.5%	9.5%	1.0220	9.7%
3	Dominion Resources	14.0%	14.5%	14.5%	14.3%	1.0366	14.9%
4	DPL, Inc.	24.5%	25.0%	25.5%	25.0%	1.0307	25.8%
5	Exelon Corp.	19.0%	17.5%	14.0%	16.8%	1.0240	17.2%
6	NextEra Energy	14.5%	11.5%	11.5%	12.5%	1.0441	13.1%
7	Pepco Holdings	5.5%	6.0%	7.5%	6.3%	1.0180	6.4%
8	PPL Corp.	11.5%	12.5%	11.5%	11.8%	1.0816	12.8%
9	Pub Sv Enterprise Grp	16.0%	15.0%	12.5%	14.5%	1.0398	15.1%
10	UIL Holdings	10.0%	9.0%	9.0%	9.3%	1.0831	10.1%
	Range of Reasonableness						**6.4% -- 25.8%**
	Adjusted Range of Reasonableness (d)						**9.7% -- 17.2%**
	Midpoint						**13.5%**
	Median (d)						**12.9%**

(a) The Value Line Investment Survey (Sep. 24 & Nov. 26, 2010).
(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit No. NPT-606.
(c) (a) x (b).
(d) Excludes highlighted values.

EXPECTED EARNINGS APPROACH

RATINGS SCREEN PROXY GROUP

		(a)				(b)	(c)		
		Return on Equity ("r")				**Adjustment**	**Adjusted Return**		
	Company	**2010**	**2011**	**2014**	**Average**	**Factor**	**on Common Equity**		
1	American Elec Pwr	9.0%	10.5%	10.0%	9.8%	1.0325		10.2%	
2	Exelon Corp.	19.0%	17.5%	14.0%	16.8%	1.0240		17.2%	
3	Pepco Holdings	5.5%	6.0%	7.5%	6.3%	1.0180		6.4%	
4	PPL Corp.	11.5%	12.5%	11.5%	11.8%	1.0816		12.8%	
5	Pub Sv Enterprise Grp	16.0%	15.0%	12.5%	14.5%	1.0398		15.1%	
6	UIL Holdings	10.0%	9.0%	9.0%	9.3%	1.0831		10.1%	
	Range of Reasonableness						**6.4%**	--	**17.2%**
	Adjusted Range of Reasonableness (d)						**10.1%**	--	**17.2%**
	Midpoint							**13.7%**	
	Median (d)							**12.8%**	

(a) The Value Line Investment Survey (Sep. 24 & Nov. 26, 2010).
(b) Adjustment to convert year-end "r" to an average rate of return from Exhibit No. NPT-606.
(c) (a) x (b).
(d) Excludes highlighted values.

CAPITAL STRUCTURE

NATIONAL PROXY GROUP

		At December 31, 2009 (a)			Value Line Projected 2013-15 (b)		
	Company	**Long-term Debt**	**Preferred**	**Common Equity**	**Long-term Debt**	**Other**	**Common Equity**
1	Ameren Corp.	47.6%	0.0%	52.4%	46.0%	0.0%	53.0%
2	American Elec Pwr	57.0%	0.2%	42.8%	52.0%	0.0%	47.5%
3	Avista Corp.	49.3%	2.4%	48.3%	49.5%	0.0%	50.5%
4	Black Hills Corp.	49.2%	0.0%	50.8%	49.5%	0.0%	50.5%
5	CenterPoint Energy	72.6%	0.0%	27.4%	67.6%	0.0%	32.5%
6	Cleco Corp.	54.4%	0.0%	45.6%	46.5%	0.0%	53.5%
7	CMS Energy	69.2%	2.5%	28.3%	66.0%	0.0%	31.5%
8	DTE Energy Co.	51.1%	2.1%	46.7%	51.5%	0.0%	48.5%
9	Edison International	49.6%	4.2%	46.3%	52.0%	0.0%	44.5%
10	Great Plains Energy	53.2%	0.6%	46.2%	53.5%	0.0%	46.0%
11	Hawaiian Elec.	48.0%	1.2%	50.7%	47.0%	0.0%	52.0%
12	IDACORP, Inc.	50.3%	0.0%	49.7%	49.5%	0.0%	50.5%
13	Integrys Energy Grp	46.3%	0.9%	52.7%	48.5%	0.0%	51.0%
14	ITC Holdings Corp.	70.6%	0.0%	29.4%	71.0%	0.0%	29.0%
15	Pepco Holdings	54.0%	0.0%	46.0%	52.0%	0.0%	48.0%
16	PG&E Corp.	50.3%	1.2%	48.5%	44.5%	0.0%	54.5%
17	Pinnacle West Capital	52.2%	0.0%	47.8%	46.0%	0.0%	54.0%
18	Portland General Elec.	53.1%	0.0%	46.9%	50.0%	0.0%	50.0%
19	PPL Corp.	55.1%	0.0%	44.9%	45.5%	0.0%	53.5%
20	Progress Energy	56.1%	0.4%	43.5%	53.0%	0.0%	47.0%
21	TECO Energy	61.3%	0.0%	38.7%	58.0%	0.0%	42.0%
22	UIL Holdings	56.0%	0.0%	44.0%	60.0%	0.0%	40.0%
23	Westar Energy	52.3%	0.5%	47.2%	53.5%	0.0%	46.0%
24	Wisconsin Energy	53.7%	0.4%	45.9%	49.5%	0.0%	50.5%
	Average	**54.7%**	**0.7%**	**44.6%**	**52.6%**	**0.0%**	**46.9%**

(a) Company 2009 Form 10-K Reports available at http://www.sec.gov/edgar/searchedgar/companysearch.html.
(b) The Value Line Investment Survey (Sep. 24, Nov. 5, & Nov. 26, 2010).

CAPITAL STRUCTURE

REGIONAL PROXY GROUP

		At December 31, 2009 (a)			Value Line Projected 2013-15 (b)		
	Company	**Long-term Debt**	**Preferred**	**Common Equity**	**Long-term Debt**	**Other**	**Common Equity**
1	American Elec Pwr	57.0%	0.2%	42.8%	52.0%	0.5%	47.5%
2	Consolidated Edison	50.3%	1.0%	48.7%	48.5%	0.0%	51.5%
3	Dominion Resources	59.2%	0.9%	39.9%	54.5%	1.0%	45.0%
4	DPL, Inc.	54.1%	0.9%	45.0%	47.5%	0.0%	52.5%
5	Exelon Corp.	47.8%	0.4%	51.9%	45.0%	0.0%	55.0%
6	NextEra Energy	56.5%	0.0%	43.5%	52.0%	0.0%	48.0%
7	Pepco Holdings	54.0%	0.0%	46.0%	45.5%	0.0%	53.5%
8	PPL Corp.	55.1%	0.0%	44.9%	52.0%	0.0%	48.0%
9	Pub Sv Enterprise Grp	44.1%	0.5%	55.4%	40.0%	0.0%	60.0%
10	UIL Holdings	56.0%	0.0%	44.0%	60.0%	0.0%	40.0%
	Average	**53.4%**	**0.4%**	**46.2%**	**49.7%**	**0.2%**	**50.1%**

(a) Company 2009 Form 10-K Reports available at http://www.sec.gov/edgar/searchedgar/companysearch.html.
(b) The Value Line Investment Survey (Sep. 24 & Nov. 26, 2010).

CAPITAL STRUCTURE

RATINGS SCREEN PROXY GROUP

		At December 31, 2009 (a)			Value Line Projected 2013-15 (b)		
	Company	**Long-term Debt**	**Preferred**	**Common Equity**	**Long-term Debt**	**Other**	**Common Equity**
1	American Elec Pwr	57.0%	0.2%	42.8%	52.0%	0.5%	47.5%
2	Exelon Corp.	47.8%	0.4%	51.9%	45.0%	0.0%	55.0%
3	Pepco Holdings	54.0%	0.0%	46.0%	45.5%	0.0%	53.5%
4	PPL Corp.	55.1%	0.0%	44.9%	52.0%	0.0%	48.0%
5	Pub Sv Enterprise Grp	44.1%	0.5%	55.4%	40.0%	0.0%	60.0%
6	UIL Holdings	56.0%	0.0%	44.0%	60.0%	0.0%	40.0%
	Average	**52.3%**	**0.2%**	**47.5%**	**49.1%**	**0.1%**	**50.7%**

(a) Company 2009 Form 10-K Reports available at http://www.sec.gov/edgar/searchedgar/companysearch.html.
(b) The Value Line Investment Survey (Sep. 24 & Nov. 26, 2010).

SUMMARY OF COST OF EQUITY ESTIMATES

Exhibit No. NPT-613
Page 1 of 1

	Adjusted Range				
DCF Method	**Low**		**High**	**Midpoint**	**Median**
National Proxy Group	7.7%	--	16.4%	12.1%	10.4%
Regional Proxy Group	7.7%	--	16.4%	12.1%	10.2%
Ratings Screen Proxy Group	8.6%	--	16.4%	12.5%	11.2%
Non-Utility Proxy Group	8.1%	--	17.5%	12.8%	12.1%
Average - DCF	8.1%	--	16.7%	12.4%	11.0%
CAPM Approach					
National Proxy Group	9.0%	--	12.1%	10.5%	10.8%
Regional Proxy Group	9.5%	--	11.7%	10.6%	10.4%
Ratings Screen Proxy Group	10.4%	--	11.7%	11.1%	10.8%
Non-Utility Proxy Group	8.5%	--	11.7%	10.1%	10.8%
Average - CAPM	9.3%	--	11.8%	10.6%	10.7%
Expected Earnings Approach					
Value Line Electric Utilities	--		--	--	10.5%
National Proxy Group	8.1%	--	15.1%	11.6%	9.9%
Regional Proxy Group	9.7%	--	17.2%	13.5%	12.9%
Ratings Screen Proxy Group	10.1%		17.2%	13.7%	12.8%
Average - Expected Earnings	9.3%	--	16.5%	12.9%	11.5%

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Northern Pass Transmission LLC	)	**Docket No. ER11-___-000**
	)	

VERIFICATION

State of Texas)
) ss.
County of Travis)

I, William E. Avera, am submitting this testimony in the above-captioned proceeding for Northern Pass Transmission LLC. My business address is 3907 Red River, Austin, Texas, 78751. I submit this verification to verify that the Prepared Direct Testimony of William E. Avera was prepared by me, with the assistance of others working under my direction and supervision, and that the contents are true to the best of my knowledge, information and belief. Executed in Austin, Texas this 14th day of December, 2010.

William E. Avera

SUBSCRIBED AND SWORN to before me
on this 14th day of December, 2010.

Notary Public

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp. Jan. 10, 2011

My commission expires: 1/10/2011

Appendix G

Charles River Associates Report
Exhibit No. NPT-700

CRA Charles River Associates

Prepared For:

Northern Pass Transmission

LMP and Congestion impacts of Northern Pass Transmission Project

FINAL REPORT

Prepared By:

Charles River Associates

200 Clarendon Street

Boston Massachusetts 02116

Date:

CRA Project No.

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1. INTRODUCTION AND SUMMARY

1.1. Purpose and Overview of analysis

Northeast Utilities ("NU") and NSTAR subsidiaries have entered into a joint venture, Northern Pass Transmission LLC ("NPT"), to develop the Northern Pass Transmission Line ("NPT Line" or the "NPT Project"). On October 4, 2010, NPT entered into a forty year transmission service agreement with H.Q. Hydro Renewable Energy, Inc. ("HQHRE"), to facilitate delivery of power generated in Québec to the New England transmission system. The NPT Line will provide capacity to deliver up to 1,200 MW of power to New Hampshire, allowing a significant amount of power generated by plants burning fossil fuels to be replaced with imported power generated predominantly by hydroelectric facilities in Québec. The additional deliveries of power from Québec to New England will supplement imports on the current ties between the systems, which are fully utilized in most peak hours throughout the year. The capacity provided by the NPT Line will therefore relieve congestion on the transmission interface between Québec and ISO New England Inc. ("ISO-NE") by allowing more competitively priced power from low incremental cost resources in Québec to be delivered in the hours when New England prices are highest but existing transfer capacity is exhausted.

At the request of NPT, CRA has prepared an assessment of the congestion mitigation impacts of the NPT Line and resulting price reductions in New England. This report summarizes CRA's analysis of the ISO-NE electricity market and power system under scenarios with and without the NPT Line in service. Specifically, CRA has estimated the hourly operations of the ISO-NE system for each scenario and compared electricity prices, wholesale power costs, and power plant operations between the two scenarios to quantify the impact of the congestion mitigation and increased supply provided by the NPT Line.

Section 1.2 provides a summary of the principal results of CRA's study. Section 2 follows with background information about the NPT Project, the Hydro Québec system, the ISO-NE market, and the expected impact of the Line. Section 3 describes the analytical methodology and key assumptions utilized in the study. Section 4 presents the quantitative results regarding the impact of the NPT Line and Section 5 provides a summary of key conclusions.

1.2. Principal Results

The principal results of CRA's analysis include:

- The NPT Line will reduce congestion between Québec and ISO-NE by:
  - (i) allowing more competitively priced energy to be imported in ISO-NE, displacing higher cost generation on the ISO-NE system, and
  - (ii) allowing more of the energy imported from Québec to be delivered during peak hours when marginal generation costs and prices in New England are highest.

  This reduced congestion will lower New England power prices and reduce costs for wholesale load customers. CRA's base case estimate of the cost reduction to wholesale load customers is $1.58/MWh, or $206 million in 2015 and $2.30/MWh, or $327 million in 2024. These wholesale cost savings should be passed on to retail

customers through lower electricity rates driven by lower prices in standard offer procurements and lower costs to competitive retail suppliers.

- Without the NPT Line, existing ties are expected to be fully utilized in 99.8 percent of peak hours. The capacity of the NPT Line allows energy delivered in other, lower-priced hours, or delivered to lower-priced locations in New York and Ontario, to be reallocated to deliveries in New England during these peak hours, when (and where) the power is most valuable.
- Based on the quantity of energy expected to be available for Hydro Québec (referred to as either "Hydro Québec" or "HQ" herein), the parent company of HQHRE, to export from Québec to neighboring markets, CRA's analysis shows that as much as 7.7 TWh of energy would be delivered to ISO-NE via the NPT Line in 2015, the first year the Line is expected to be operational. By 2024, imports on the Line are expected to grow to 8.9 TWh, with the increased utilization driven by expansion of the hydroelectric generating capacity in Québec. Accounting for reductions in the net imports of power into ISO-NE on other AC and DC ties with neighboring markets, the analysis shows that total net imports to New England will increase by 5.3 TWh in 2015 and 6.4 TWh in 2024. This modeled level of exports from Québec is based on projected export capability for the Hydro Québec system. Under open access provisions in the TSA, other competitive power marketers may also have access to unused transmission capability on the Line from time-to-time, potentially allowing for additional utilization.
- In order to provide a conservative estimate of the reduction in congestion and wholesale power costs in New England, CRA's analysis has examined a base case with assumptions that represent conservative expectations for market conditions. The likely range of actual market conditions also includes scenarios under which the reduction in congestion, displacement of thermal generation, and wholesale cost reductions would be greater. In particular, higher natural gas prices, more limited renewable capacity additions, and unit retirements would all tend to increase the benefits of the project. Moreover, CRA has conservatively assumed that currently projected growth in exports from Québec will occur whether or not the NPT Line is built. However, absent the NPT Line, these additional exports would be delivered during lower value periods with lower net revenues to Hydro Québec, which could result in delaying the development of the resources that will allow growth in total exports. If more projects supporting exports were developed as a result of the NPT Line, the impact of the line on imports, reduction in fossil-fueled generation in New England, and wholesale cost reductions would be greater.
- Under the base case scenario modeled, the increased net imports to New England would lead to the displacement of generation from fossil-fueled generators totaling 5.3 TWh in 2015, most of which will be from gas-fired generating units. If, as a result of their ongoing build of new hydro-electric facilities, Hydro Québec has more surplus energy than modeled, exports could increase to a level that would support additional deliveries on the NPT line, up to 10.5 TWh. For every additional TWh of imports that displaces gas-fired generation, carbon emissions would be reduced by approximately 0.44 million tons, up to 5 million tons total.

- The NPT Line will also provide reliability and fuel diversity benefits. The 1,200 MW of firm capacity that can be imported over the Line will add to the ISO-NE reserve margin for several years and, based on the current ISO-NE demand forecast, delay the need for constructing new capacity within ISO-NE by 4 to 5 years. Additionally, the Project will enhance reliability by reducing the region's dependence on natural gas, particularly during high gas demand periods in the winter months. Under CRA's 2015 base case the power transfers across the NPT Line are expected to displace 24.7 Tcf of natural gas in New England.

2. BACKGROUND

2.1. THE NORTHERN PASS TRANSMISSION PROJECT

The NPT Line will consist of (i) a 1,200 MW high voltage direct current ("HVDC") transmission line from the United States-Canadian border to a converter station to be constructed in the City of Franklin, New Hampshire, and (ii) a radial 345 kV alternating current ("AC") transmission line between the Franklin converter station and the Deerfield substation owned by NU subsidiary, Public Service Company of New Hampshire, where it will interconnect with the ISO-NE transmission system. On the Canadian side of the border, the NPT Line will connect with a new HVDC transmission line to be constructed by Trans-Energie, a transmission division of Hydro-Quebec, into the Des Cantons substation in Québec. The NPT Line will be constructed to have the capability to transmit up to 1,200 MW of power, supplementing the existing ties between Québec and New England, which includes an interconnection to Sandy Pond in central Massachusetts and an interconnection to Highgate in Vermont. Major construction is expected to begin in 2013, with a target in service date in 2015.

The NPT Line will support sales of surplus energy and capacity available in Québec. The energy from the Québec system is generated almost entirely from hydroelectric power stations, which will be supplemented with the output from new hydro projects under construction or currently under development. The variable operating costs for these generating facilities is extremely low. By contrast, natural gas is the predominant fuel for electric generation in New England, leading to significantly higher operating costs and market prices. Given the large differential between the low power costs in Québec and the high electricity prices in the ISO-NE market, the existing ties between the two systems are very highly utilized, especially during peak periods. The NPT Line will provide additional delivery capacity during many on-peak hours when the existing ties are fully utilized, but a large differential between the system marginal cost in Québec and the market price in ISO-NE remains. The additional capacity provided by NPT will therefore mitigate transmission congestion between the two systems.

2.2. HYDRO QUÉBEC SYSTEM

2.2.1. Existing Resources and Load Responsibilities

A division of Hydro Québec, Hydro-Québec Production ("HQP"), owns and operates one of the largest fleets of zero-carbon generation in the world. HQP's current fleet of generating facilities consists of 36,810 MW of installed capacity:

Source	*Number of Units*	*Installed Capacity*
Hydroelectric generating stations	60	34,499 MW
Nuclear generating station	1	675 MW
Thermal generating stations	27	1,634 MW
Wind farm	1	2 MW

Source: Hydro-Québec, http://www.hydroquebec.com/generation/index.html

Expected annual production from the hydroelectric facilities is 166.7 TWh, depending upon water availability. The Gentilly-2 nuclear station produces 5.2 TWh annually when at normal availability. The thermal generation plants, principally the 600 MW Tracy steam plant, are lightly utilized and contribute only 0.2 TWh of electricity annually, on average.[1]

Additionally, Hydro-Québec has contracts to purchase the output from all, or substantially all, of the output from an additional 7,382 MW of installed capacity:

Source	*Number of Units*	*Installed Capacity*
Churchill Falls generating station	1	5,428 MW
Privately owned wind farms	8	657 MW
Other independent power producers		1,297 MW

Source: Hydro-Québec, http://www.hydroquebec.com/generation/index.html

Long-term purchase arrangements contribute an expected 35.4 TWh to the Hydro-Québec system annually; additional purchases from independent power producers are expected to add a further 0.5 TWh annually.

As the franchise utility for the province, Hydro-Québec also has substantial load-serving responsibility. Hydro-Québec expects to deliver 188 TWh of power (including associated delivery losses) within Québec in 2010, plus an additional 2.9 TWh for contractual deliveries outside of Québec. This leaves the system with approximately a 15 TWh margin of flexibility for managing low runoff risk and for short-term sales.

[1] See HQ's Environmental Impact Assessment Study - Romaine Complex - Volume I, December 2007, table 2-8, page 2-10, available in French at: http://www.hydroquebec.com/romaine/pdf/ei_volume01.pdf

In terms of peak energy, the Hydro-Québec system has an expected capacity requirement of 39,519 MW for the 2010–2011 power year, of which 482 MW are for short- and long-term contracts outside of the province. After accounting for purchases and operating considerations, Hydro-Québec has sufficient capacity to support an expected minimum of 1,249 MW of sales in 2010–2011, with significantly more capacity available to support exports in most hours. It is particularly noteworthy that Québec is a winter-peaking system, so additional capacity is available for sale during the summer to meet New England's peak loads. As a result, annual energy limits are a more relevant constraint to exports than are capacity constraints.

2.2.2. Plans for Expansion in Québec

Québec has substantial amounts of untapped renewable energy resources from further large-scale hydroelectric development. HQP has brought several new hydro-electric facilities into service recently. Its Mercier, Peribonka, Rapide-des-Coeurs, and Chute-Allard facilities have been in full-scale commercial operation since 2007, which, together with various upgrades to existing facilities, has added 621 MW of capacity and 9.4 TWh of energy to the Hydro-Québec system.

Going forward, HQP has three major hydroelectric projects under construction:

1. The Eastmain-1-A facility, with 768 MW of capacity and 2.3 TWh of energy;
2. The Sarcelle facility, with 125 MW of capacity and 0.9 TWh of energy.
3. The Romaine Complex, which will add 640 MW of capacity (3.0 TWh) in 2015, potentially ramping up to 1,550 MW of capacity (8.0 TWh) by 2021.

Collectively, these projects and related upgrades to existing resources will add 2,506 MW of capacity and 16.7 TWh of energy on the Hydro-Québec system.[2]

Looking into the future, Hydro-Québec has a strategy to add a further 3,000 MW of hydroelectric capacity. The timing of these projects "will take into account power market conditions here in Québec and in neighboring provinces and states."[3] An additional block of 3,000 MW of hydroelectric power is also contemplated for the northern area of the province.

2.2.3. Interconnections to the U.S. and Other Canadian Provinces

Although Hydro-Québec's TransÉnergie transmission system is not synchronized with the Eastern Interconnection, it is well interconnected to all of the neighboring markets, as shown in Table 1.

[2] Hydro-Québec, "Strategic Plan 2009–2013", p.20·

[3] Id., at 22·

Table 1: Hydro Québec External Ties

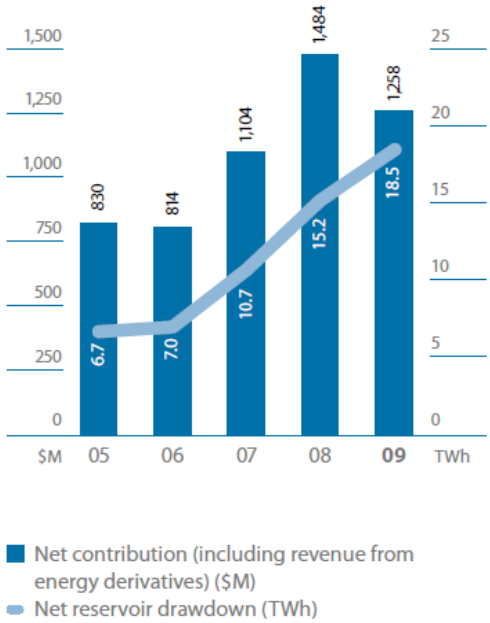
Neighboring System	*Import Mode (MW)*	*Export Mode (MW)*
New York	1,100	2,000
Ontario – Existing	695	1,455
Ontario – New	1,250	1,250
New England – Existing	1,870	2,275
New Brunswick	785	1,080
Newfoundland and Labrador	5,150	0

Source: Hydro-Québec, http://www.hydroquebec.com/transenergie/en/reseau/bref.html

The above table does not include the additional transfers of up to 1,200 MW that the NPT Project would allow between Québec and New England.

Since markets were deregulated in 1999, HQP, through its U.S.-based marketing affiliate HQ Energy Services Inc. ("HQUS"), has engaged in energy trading in the U.S. Northeast: sales of electricity produced in Québec, purchase/resale operations and price arbitraging. Since the early 2000s, HQP has also exported electricity to Ontario at market prices. As Figure 1 shows, HQP's exports have risen substantially over the last decade, nearly tripling from 6.7 TWh in 2005 to 18.5 TWh in 2009.

Figure 1: Hydro Québec Exports



Source: HQ Annual Report, 2009

2.2.4. Expected Future Export Potential

The combination of increased production capability in Québec resulting from the addition of new hydroelectric will allow Hydro-Québec to continue to increase its exports going forward. Hydro-Québec projects that the *installed capacity* available for long-term sales will more than double from 1,249 MW in the 2010–2011 power year to 2,862 MW in the 2020–2021 power year, even taking into account increased demand in the province. In parallel, Hydro-Québec forecasts that the amount of *energy* available for long-term sales will increase to nearly 24 TWh by 2013.[4] By 2021, potential export capacity is expect to grow to approximately 30 TWh.[5] The ability to *deliver* these incremental volumes during periods when cost in the destination markets are highest, however, is dependent upon increasing the interconnection links between Québec and potential export markets, including, for example, the NPT Project into New England. This modeled level of exports from Québec is based on projected export capability projected for the Hydro Québec system. Other competitive power marketers will also have access to released transmission capability on the NPT Line, potentially allowing for additional utilization.

2.3. ISO NEW ENGLAND MARKET

2.3.1. Overview

ISO-NE was formed in 1997 to operate the power markets in the New England region, and became the regional transmission organization ("RTO") in 2005. ISO-NE serves as the independent system and market operator for the members of the legacy New England Power Pool ("NEPOOL") organization, a voluntary association of market participants that now serves as the primary stakeholder advisory group to ISO-NE.

ISO-NE operates the Day-Ahead and Real-Time Energy Markets, along with markets for installed capacity and ancillary services. Figure 2 show the ISO-NE footprint, which includes eight major load zones covering all of the New England states, with the exception of the far northern part of Maine. Over 500 generating units are interconnected within the ISO-NE system, almost 33 GW of supply to meet peak summer demand, along with an additional 2,300 MW of Demand Response capacity.[6] The all-time record peak demand of 28,130 MW was reached in August 2006 during very hot conditions. The 2009 peak demand of 25,081 MW was significantly lower, reflecting milder weather and the effects of the current economic downturn. The weather-normalized peak for 2009 was estimated to be 27,460 MW, demonstrating the significant impact of the mild summer weather on demand. The summer peak for 2010 was 27,100 MW.

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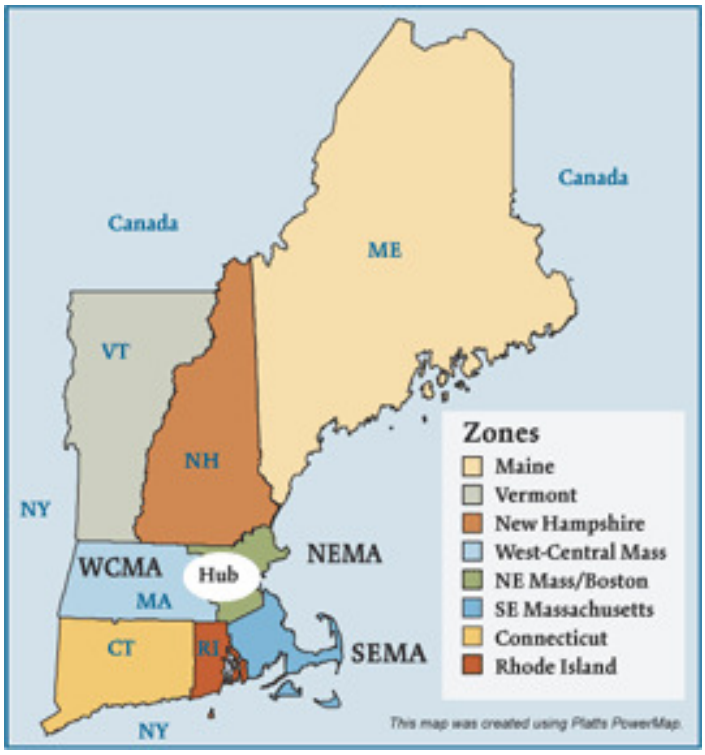
[4] See HQ's Strategic Plan 2009-2013, page 25, available at: http://www.hydroquebec.com/publications/en/strategic_plan/index.html.

[5] See HQ's Environmental Impact Assessment Study - Romaine Complex - Volume I, December 2007, table 2-8, page 2-10, available in French at: http://www.hydroquebec.com/romaine/pdf/ei_volume01.pdf

[6] System capacity is based on summer capacity from ISO-NE Seasonal Claimed Capacity Report; October 1, 2010. Demand response capacity is cleared demand response from the FCM Forward Capacity Auction for the 2010/11 Commitment Period.

Figure 2 New England (ISO-NE) Electric Regions



ISO-NE currently has ample supply. The projected reserve margin for the summer of 2010 is 33 percent with a capacity reserve of 7,519 MW, which exceeds the required amount by 2,404 MW. ISO-NE administers a Forward Capacity Market ("FCM") in order to secure sufficient resources three years in advance of each planning year. Excluding resources that do not have a firm capacity obligation from the Forward Capacity Auction ("FCA") for the 2010/11 FCM Commitment Period, the surplus is 1,774 MW. Based on the Installed Capacity Requirement ("ICR") applied in the most recent FCM auction (for the 2012/13 FCM Commitment Period), the target minimum reserve margin for ISO-NE is approximately 15 percent; in the longer-term, the market should trend toward this reserve margin level.

2.3.2. Energy Market

In 2003, ISO-NE implemented a Standard Market Design ("SMD") framework with a two-settlement spot energy market consisting of a Day-Ahead Market ("DAM") and a Real-Time Market ("RTM"). The DAM enables market participants to purchase and sell energy at binding Day-Ahead prices. This market is cleared based on submitted supply offers and demand bids using a least-cost security-constrained unit commitment algorithm. The DAM produces financially binding obligations and schedules for demand and generation. The ISO-NE dispatch and market clearing process determines Locational Marginal Prices (LMPs) for energy at over 900 nodes throughout the region. These prices are the sum of a reference energy cost, plus local loss and congestion terms. Through the DAM, ISO-NE produces

hourly LMP pricing, and it also schedules commitments for generation and external transactions for the next day.

Load obligations are settled at zonal prices, which are determined as load-weighted average of nodal prices within each of eight load zones within ISO-NE (three in Massachusetts plus one for each of the other five states). The "Mass Hub" price is the unweighted average of 32 nodal prices in central Massachusetts; this hub was created to facilitate bilateral trading and is traded on the New York Mercantile Exchange ("NYMEX").

Projected spot prices for power in these ISO-NE administered competitive wholesale markets provides a very good indicator of the ultimate cost of wholesale power that will be passed on to retail customers. As a result of industry restructuring, New England's electric distribution utilities and other load serving entities own and operate only a small percentage of the region's generating capacity, but rather serve their customers' demand through wholesale purchases from the competitive market, the costs of which are ultimately recovered through retail rates charged to end-use customers. Numerous New England customers pay a retail rate tied to prices set in periodic Standard Offer Service auctions, which in turn closely ties to expected wholesale power costs. Wholesale power costs are therefore a good measure of electricity costs for consumers in the New England Region.

2.3.3. Capacity and Generation Mix

ISO-NE currently has generation resources that together provide Summer Claimed Capability of 30,146 MW.[7] Demand-side resources (DR) and Emergency Generation provide an additional 1,679 MW and 600 MW, respectively, of capacity resources, along with 934 MW of capacity from imports (excluding the HQICC[8]). Together, these resources provided a reserve margin of nearly 33 percent against the 2010 peak load forecast.

Figure 3 shows the Summer 2010 generation supply curve for ISO-NE. The installed capacity base in New England is dominated by gas- and oil-fired generation, as shown by the long, flat portion of the supply curve, consisting of combined cycle capacity, and the gas- and oil-fired steam and peaking capacity at the right end of the curve. Approximately 50 percent of ISO-NE capacity is either gas-fired (26%) or gas/oil dual-fueled (24%). Oil-fired generators (without dual-fuel capability) contribute another 15 percent, with hydro, nuclear, and coal capacity making up most of the rest of the New England fleet. Gas- and oil-fired generation set market prices a large percentage of the time in New England. Over the last few years, these generators were on the margin in more that 60 percent of the ISO-NE dispatch intervals.[9]

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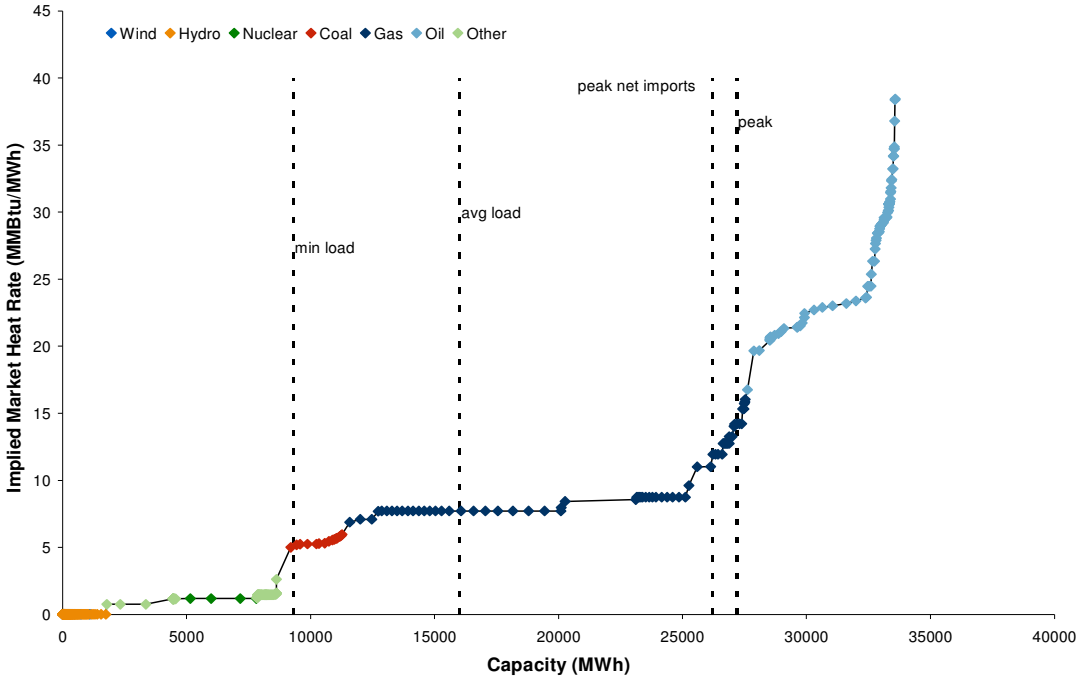
[7] ISO-NE Summer Claimed Capability Report, November 1, 2010.

[8] Hydro Québec Interconnection Capacity Credits (HQICC) are capacity credits that the holders of transmission rights across the Phase I/II interconnection ("Interconnection Rights Holders" or IRH) can use to satisfy their capacity obligations under the New England Forward Capacity Auction (FCA). And therefore lower the total quantity procured in the FCA.

[9] 2009 ISO-NE Annual Markets Report

Figure 3: ISO-NE Supply Curve, Summer 2010



Planned New Capacity

Existing New England generating capacity, along with expected imports and DR resources, is expected to be sufficient to meet system needs several years into the future. As a result of new resources that are planned to come on-line in the next several years, all near-term needs and capacity requirements will be met for several additional years. These generating resources represent capacity secured in the first four FCAs. Additionally, significant new DR resources have been secured in the auctions.

New resources totaling 626 MW that were secured through the first FCA have either recently come on-line or are scheduled to enter commercial operation before the end of 2010. In addition, several additional new units have capacity supply obligations from the second and third FCAs and should enter service over the next two years, along with a small amount of new capacity that cleared in the fourth FCA.

Another important source of capacity resources for New England is demand response. Existing DR sources totaling 1,367 MW (1,092 MW after prorating for joint feasibility) cleared in the first FCA and 1,187 MW of new DR cleared, for a total of 2,279 MW counting toward the regional capacity requirement. Additional resources secured through the second and third FCA have brought the total DR for the 2012/13 FCM Capacity Commitment Period up to 2,867 MW. Hence, DR totaling about 10 percent of the ISO-NE forecast peak will be available as capacity resources.

The generation mix in New England creates attractive export opportunities for a supplier such as HQ. With gas- or oil-fired generation on the margin and setting the price in most peak hours, New England prices are very closely tied to the price of natural gas. These gas-driven prices are higher in many hours than those in markets with significant coal-fired generation.

Additionally, as much of the current capacity surplus was created by the addition of DR. New England currently has commitments from demand-side resources totaling approximately 10% of the forecasted peak load for the region. Meeting such a substantial portion of the region's requirement for reserve capacity with curtailment of demand rather than generation supply means that, under conditions of unusually high demand or unexpected loss of supply, the system operators will have to rely on emergency procedures that allow the DR to be called.

2.3.4. Transmission System and Interconnections

The ISO-NE transmission network includes over 8,000 miles of transmission lines, with twelve interconnections to Canada and New York. The transmission system includes a higher voltage (345 kV) regional backbone, as well as lower level lines connected to load and generation in the local areas within the regional network. The external ties are a combination of DC ties (two with Québec, one with Long Island) and AC lines.

Historically, the most frequently binding transmission constraints in ISO-NE have been major interfaces between zones. Figure 4 shows the major interfaces throughout the ISO-NE system. Over the last several years, the most frequently congested interfaces have been the Boston/NEMA Import Limit, the Southwest Connecticut Import Limit, the Maine-New Hampshire Interface, and the New England East-West Interface. As reflected by the relatively low price separation among the zones in Figure 5, congestion on these interfaces has diminished in both frequency and magnitude. Rather, price separation among ISO-NE regions has been attributable more to the pricing of marginal losses.

Figure 4: Major ISO-NE Interfaces

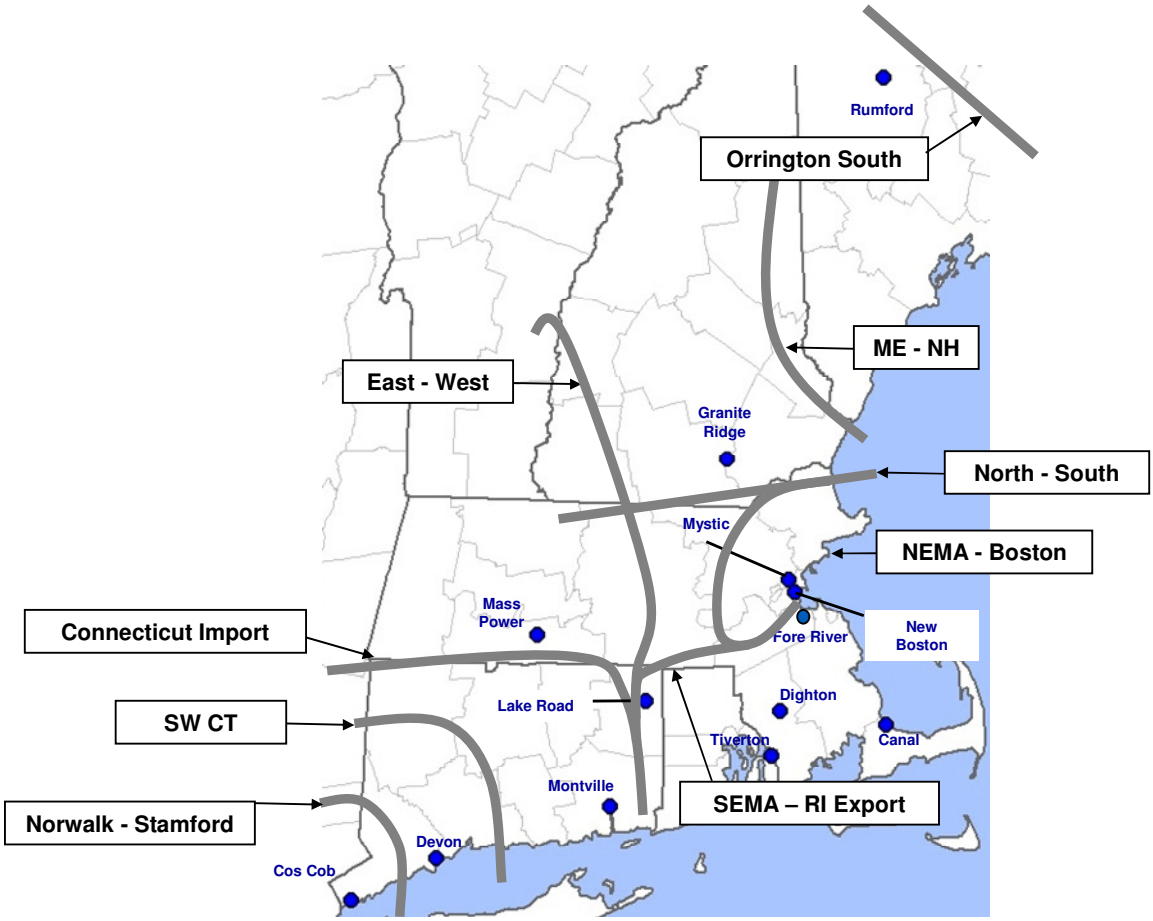
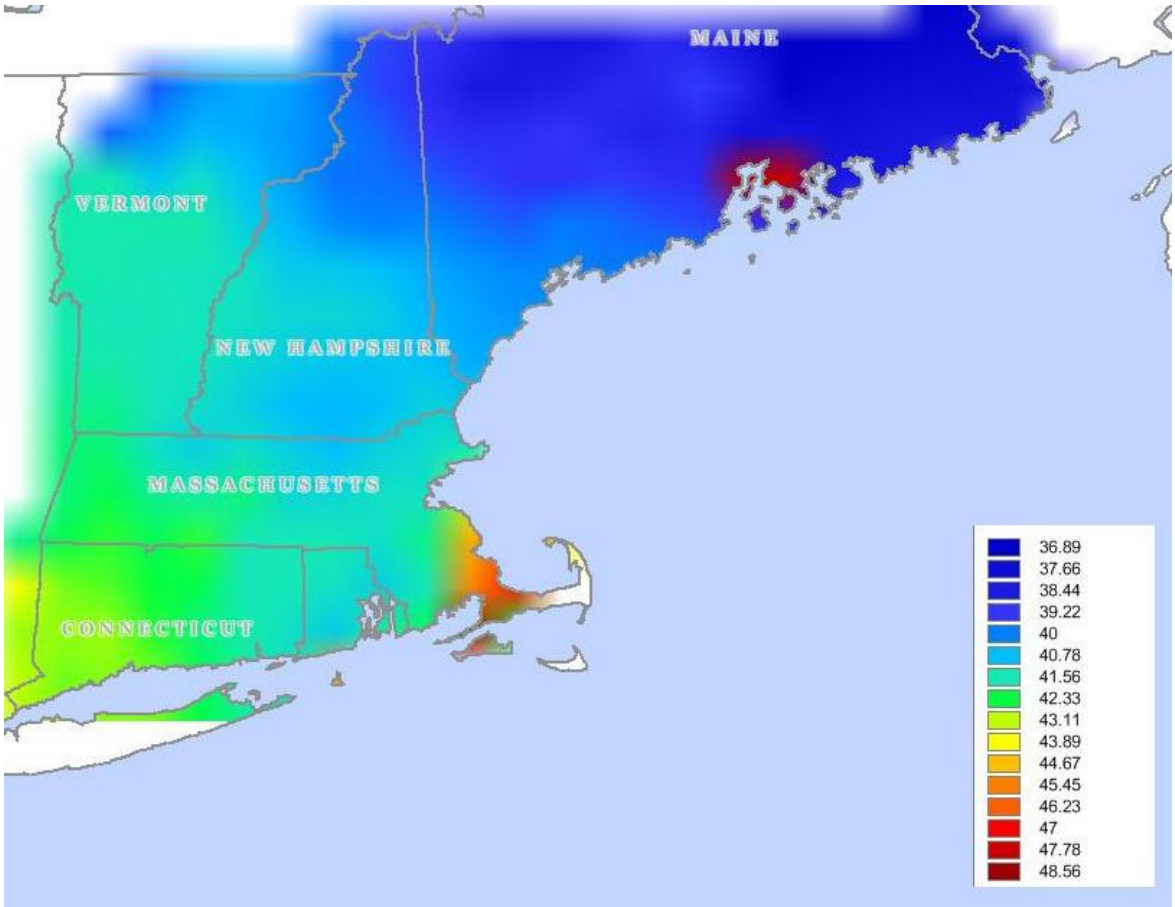


Figure 5: ISO-New England LMP Day-Ahead Patterns, 2009



The reduced level of congestion across these major interfaces is attributable to recent transmission upgrades within ISO-NE. First, upgrades to the 345 kV system in and around Boston have significantly reduced congestion for the NEMA zone, while supporting higher prices in SEMA as separation between the two zones has declined. Similarly, upgrades to the Connecticut transmission system through the Southwest Connecticut Reliability Project, which includes 345 kV upgrades, allows more power to flow into the Norwalk-Stamford and Southwest Connecticut load pockets.

With these internal transmission upgrades in place, congestion has not been completely eliminated, however. Additional congestion has occurred on the New England East-West and Connecticut Import Interfaces, essentially reflecting a shift in the bottleneck from Southwest Connecticut back to the Connecticut border. Several potential transmission upgrades have been proposed to help mitigate this congestion and prevent additional congestion on the interfaces as loads increase. The planned upgrades are part of the New England East-West Solution (NEEWS) project, consisting of four projects designed to reduce this congestion and provide other reliability benefits. The projects are proposed for completion in the 2013 – 2016 time frame. The other major transmission upgrade recently completed in New England is the Maine to New Brunswick Interconnector, which significantly increases the ability for Maine to import power from the Maritimes region.

In addition to NPT, other major transmission projects currently under review in ISO-NE include:

- A proposed line from Scobie (in NH) to Tewksbury (in MA), which would facilitate additional flows from Maine and New Hampshire south to NEMA.
- The Green Line project, which would bring power from Maine into Southern New England.

All of these projects are still under development without a definitive timetable for construction or commitment to move forward. Although the Scobie-Tewksbury line is not yet part of the regional system plan, ISO-NE has identified either this line or an equivalent overhead transmission upgrade that is needed to help solve reliability problems in the greater Boston area and relieve a significant bottleneck at the North-South interface. Therefore, CRA has included the Scobie-Tewksbury line in the analysis.

2.3.5. Historical Pricing

Two major trends become apparent when looking at historical power prices in New England:

1. The close relationship between power prices and natural gas prices, particularly during peak hours
2. The decrease in price separation across New England

New England's generation fleet is dominated by gas-fired combined cycle capacity, tying power prices tightly to the natural gas market during most peak hours. As shown in Table 2 and Table 3, power prices across New England have followed the trends in the natural gas markets over the past five years. New England power prices reflect the run up in gas prices in 2008 and the subsequent decline. These trends can be observed in both on-peak and off-peak markets[10]. The latter suggesting a limited supply of base load generation, that allows intermediate generating resources, e.g. combined cycle generating plants, to set prices during hours that were traditionally covered by coal and nuclear generation.

Transmission upgrades, such as the NSTAR 345 kV cables into the Boston area and the two phases of the 345 kV Southwest Connecticut Reliability project increased the transfer capability between transmission zones and greatly reduced the congestion potential across New England.

[10] The on-peak period in New England is defined as a 16-hour period between 7 a.m. and 11 p.m. on weekdays. The remaining night time hours on weekdays and all hours on both Saturday and Sunday are defined as off-peak periods.

Table 2: Zonal Congestion and Losses for ISO-NE, Peak Hours ($/MWh)

On-Peak		Mass Hub	CT	ME	NEMA-Boston	NH	RI	SEMA	VT	WCMA
2005	LMP	88.81	96.62	78.87	91.96	84.52	85.50	85.45	89.02	89.00
	Congestion	-	7.15	(4.37)	4.56	(2.22)	(1.34)	(1.20)	(0.47)	(0.06)
	Losses	-	10.94	(17.26)	3.62	(7.36)	(4.85)	(5.03)	0.27	0.40
2006	LMP	69.56	79.75	64.66	69.56	67.30	67.00	67.58	70.15	69.97
	Congestion	-	9.84	(1.78)	1.06	(0.95)	(1.12)	(0.66)	0.43	0.17
	Losses	-	15.97	(8.26)	(0.46)	(3.69)	(3.91)	(2.94)	0.67	0.71
2007	LMP	77.00	82.94	72.07	75.01	75.45	74.47	76.98	78.91	77.79
	Congestion	-	4.63	(2.19)	(1.02)	(0.80)	(1.33)	1.01	1.00	0.32
	Losses	-	8.51	(7.74)	(2.76)	(2.54)	(3.94)	0.74	3.02	1.23
2008	LMP	90.94	97.41	84.78	90.04	89.25	89.36	93.68	91.60	91.87
	Congestion	-	4.63	(1.78)	(0.33)	(0.40)	(0.55)	3.42	0.33	0.46
	Losses	-	9.96	(8.66)	(1.39)	(2.70)	(2.43)	6.09	1.01	1.33
2009	LMP	46.37	48.28	43.96	46.41	45.56	45.91	46.67	46.44	46.85
	Congestion	-	1.19	(0.34)	0.31	(0.14)	(0.04)	0.39	0.00	0.20
	Losses	-	2.54	(3.79)	(0.14)	(1.38)	(0.79)	0.47	0.08	0.78
2010 YTD	LMP	55.75	58.67	52.94	54.84	54.75	54.58	54.84	56.82	56.49
	Congestion	-	1.48	(0.43)	(0.32)	(0.34)	(0.45)	(0.45)	0.38	0.25
	Losses	-	4.59	(4.80)	(1.66)	(2.09)	(1.98)	(1.57)	1.53	1.53

Table 3: Zonal Congestion and Losses for ISO-NE, Off-Peak Hours ($/MWh)

Off-Peak		Mass Hub	CT	ME	NEMA-Boston	NH	RI	SEMA	VT	WCMA
2005	LMP	69.60	71.41	63.81	69.29	67.27	68.08	67.94	69.87	69.80
	Congestion	-	1.31	(1.53)	0.78	(0.73)	(0.03)	(0.01)	(0.21)	0.02
	Losses	-	1.81	(5.79)	(0.31)	(2.33)	(1.52)	(1.66)	0.28	0.20
2006	LMP	53.46	56.48	50.62	52.83	52.24	52.26	52.49	53.54	53.70
	Congestion	-	2.77	(0.52)	0.18	(0.20)	(0.14)	0.01	0.00	0.06
	Losses	-	3.02	(2.85)	(0.64)	(1.22)	(1.20)	(0.97)	0.08	0.24
2007	LMP	60.10	61.89	57.62	59.33	59.31	58.93	60.07	61.00	60.50
	Congestion	-	0.77	(0.33)	(0.00)	(0.21)	(0.23)	0.77	0.20	0.03
	Losses	-	1.79	(2.48)	(0.76)	(0.78)	(1.17)	(0.02)	0.91	0.40
2008	LMP	71.25	73.71	68.30	70.78	70.24	70.43	72.67	71.56	71.63
	Congestion	-	1.04	0.46	(0.02)	(0.00)	(0.03)	1.93	0.05	0.01
	Losses	-	2.46	(2.95)	(0.47)	(1.01)	(0.82)	1.42	0.31	0.38
2009	LMP	37.31	37.90	35.79	37.11	36.75	36.97	37.36	37.34	37.57
	Congestion	-	0.03	0.13	0.02	(0.02)	(0.00)	0.12	(0.02)	0.04
	Losses	-	0.59	(1.51)	(0.20)	(0.55)	(0.33)	0.05	0.03	0.26
2010 YTD	LMP	41.46	42.69	39.65	40.89	40.64	40.83	40.97	41.95	42.03
	Congestion	-	0.46	(0.18)	(0.17)	(0.26)	(0.17)	(0.16)	(0.03)	0.24
	Losses	-	1.22	(1.82)	(0.58)	(0.83)	(0.63)	(0.49)	0.49	0.56

Going forward, the prevalence of combined cycle generators will remain important for pricing in the New England market, as these units will remain the marginal source of generation in many hours. However, as reserve margins tighten, prices will be set by higher cost generators more frequently. Additionally, in many peak hours DR will play an important role in market pricing, since dependence on DR to meet a large portion of reserve margin requirements is likely to lead to more periods when emergency conditions are triggered, allowing DR to be called. These conditions often lead to very high spot prices in the hourly markets for electricity, which can increase substantially the value of incremental supply, such as the import capacity provided by the NPT Line.

2.4. EXPECTED IMPACT OF THE NPT LINE

The additional import capacity provided by the NPT Line is expected to affect the ISO-NE market in several important ways. First, the Line will provide congestion relief on the tie lines connecting Québec to ISO-NE. Currently, the existing HVDC ties between the two markets are fully utilized during most peak hours. In these hours, the gas-driven New England prices are often substantially above the hydro-driven marginal generation cost in Québec, which is near zero. Allowing additional imports to New England during these hours will lower the price differential between the markets, reducing congestion.

Québec has ample hydro storage capacity, allowing Québec to export power during the hours when prices in the destination markets are highest. However, as a result of the congestion on these tie lines between Québec and New England during many of the peak hours when exports to New England would have the highest value, the energy in Québec that is available for export is instead sold in lower-demand periods, or to other markets with lower prices than New England. Hence, the additional capacity that will be provided by NPT will reduce congestion by allowing more power to be delivered during the hours when prices are highest and to the market where the power is valued most. The result of the congestion relief will be lower ISO-NE prices, lower fossil-fueled generation in New England, reduced production costs, and lower costs of wholesale power purchased through the New England market in order to serve load customers.

The NPT Line will also have benefits in terms of enhanced reliability and resource adequacy. The capacity provided by the Line will contribute to the ISO-NE reserve margin and delay the need for new capacity. Additionally, allowing more imports will help contribute to a diversified fuel mix and reduced dependence on natural gas within New England. Deliveries of power from the hydro-rich Québec system will displace gas-fired generation in New England and lower not only the total amount of gas used through the year, but also the dependence on potentially constrained gas delivery capacity during peak winter periods when gas demand is highest.

3. ANALYTICAL METHODOLOGY

3.1. Overview of Modeling Approach

CRA's projections of the market impacts of the NPT Line were derived by simulating this competitive market dispatch and market clearing process for ISO-NE and neighboring markets. CRA used the General Electric Multi-Area Production Simulation Model ("GE MAPS"), a chronological production cost model licensed by GE Power Systems. The GE MAPS model was used to estimate the market clearing prices and the associated dispatch of generating units throughout the system under scenarios both with and without the NPT Line. The results of the two cases were then compared in order to estimate the impact of the NPT Line. CRA simulated 5 years (2015, 2016, 2018, 2021, and 2024) to cover the 10-year time frame between 2015 and 2024.

The analysis was conducted using a model that covers the Northeast portion of the Eastern Interconnection, including ISO-NE, NYISO, PJM, and Ontario IESO. Because the HQ power system is not operated synchronously with the Eastern Interconnection, but rather connected to neighboring markets via DC ties, Québec generation and load are not explicitly represented in the model. Rather, each individual HVDC intertie between HQ and its neighbors is modeled[11]. As will be discussed in more detail in Section 3.3, the total quantity of energy expected to be available for export from Hydro Québec was allocated among the DC ties based on expected prices in each potential export market. The objective of the allocation was to maximize the value of the exported energy by scheduling flows on each tie in the hours and locations with the highest realized prices. Including the NPT Line allowed additional energy to be allocated for delivery to New England during hours with relatively higher clearing prices.

3.2. GE MAPS model

CRA used the GE MAPS fundamental electricity market model to estimate electricity prices and unit operations. Fundamental electricity market models simulate the dispatch and market clearing process using detailed data about demand for electricity and the power plants available to supply that demand. A fundamental model accounts for the significant market factors that drive electricity prices, such as electricity demand and fuel prices, and allows the effects of long-term changes in those factors over time to be reflected accurately. The model also accounts for hour-to-hour fluctuations in demand and unit availability.

GE-MAPS is a detailed economic dispatch and production-costing model for electricity networks. It was originally developed by General Electric (GE) and is currently used by over twenty major utilities and RTOs in the U.S. CRA has worked closely with GE and market participants to ensure that the model's data structures and dispatch logic accurately reflect the conditions and outcomes of the competitive markets being modeled.

[11] The Maritimes power system was not explicitly modeled, but imports to New England from New Brunswick were modeled to capture the impact on the New England market. Much of the flow across this interface captures exports from Québec that are wheeled through New Brunswick and ultimately delivered to the ISO-NE market.

GE MAPS calculates prices based on market supply and demand, as well as the physical properties of the electrical system. The GE MAPS model is what is referred to as a security-constrained dispatch model. It simulates the hourly chronological operation of an electricity market, accounting for limits on the flow of power across transmission lines throughout the system. Based on unit-level marginal cost bids, the model calculates a least-cost dispatch subject to thermal and contingency constraints and computes hourly, locational-based marginal prices for electricity. Zonal load prices are calculated as load-weighted averages of the relevant nodes with each zone, which is the same approach used by ISO-NE for calculating the load zone prices used to compute wholesale costs to load customers.

The model captures important details about the transmission system and other operational details that affect market pricing in ISO-NE and other neighboring markets. The GE MAPS model calculates Locational Marginal Prices (LMPs), consistent with the pricing methodology used by ISO-NE in the actual market clearing. Under an LMP scheme, a separate price is calculated for each node on the system. The locational prices reflect the relative impact of generation at each node on the level of transmission congestion and transmission line losses throughout the system, in order to capture the incremental impact of additional supply at that node on the overall system cost of meeting demand. Because the economics of energy imports on the NPT Line may be affected by transmission congestion within the ISO-NE market, capturing the details of LMP pricing is important for correctly assessing its market impacts.

3.3. Key Input Assumptions

3.3.1. Demand and Peak Load

ISO-NE demand (MWh) and peak load (MW) for GE MAPS simulations are based on the 2010 ISO-NE CELT forecast, adjusted for passive demand response (PDR). The level of PDR through 2013 is based on cleared resources from the Forward Capacity Market; thereafter it is assumed to grow proportional with energy demand. Demand and peak load for NYSIO and PJM are based on the 2010 “Gold Book” and the 2010 PJM Load Forecast, respectively. IESO demand and peak load assumptions are based on the December 2009 Ontario Reliability Outlook. The Northeast ISOs provide peak load and energy demand forecasts through 2019. Beyond 2019, CRA extrapolated the energy forecasts for each region based on the five-year compound annual growth rate. Table 4 shows the annual aggregate ISO-NE demand and peak load, before adjustments for PDR. Zonal loads for each region, along with projected levels of PDR, are shown in Appendix A.

Table 4: ISO-NE Demand and Peak Load, 2011-2024

Year	Demand (GWh)	Peak Load (MW)
2011	128,083	26,876
2012	128,110	27,092
2013	127,959	27,482
2014	129,262	27,919
2015	130,379	28,328
2016	131,511	28,650
2017	132,743	28,963
2018	134,032	29,271
2019	135,305	29,559
2020	136,565	29,875
2021	137,837	30,195
2022	139,121	30,518
2023	140,417	30,844
2024	141,725	31,174

3.3.2. Planned ISO-NE Capacity Additions and Retirements

The planned capacity additions and retirements in New England included in the study are based on actual cleared resources in the ISO-NE Forward Capacity Market. Table 5 shows the generating capacity additions assumed to enter commercial service in 2010 and beyond.

Table 5: Planned Capacity Additions in New England

Capacity Market Auction Clearings

Unit	Type	Summer Capacity (MW)	Online Date
Swanton Gas Turbine 1	Natural Gas	20	Feb-2010
Swanton Gas Turbine 2	Natural Gas	20	May-2010
Devon 15-18	Natural Gas	188	Jun-2010
Sheffield Wind Farm **	Wind	40	Nov-2010
Concord Steam	Wood Waste Solids	14	Jun-2011
Granite Reliable Power **	Wind	99	Jun-2011
Kimberly-Clark Corp Energy Independence Project	Natural Gas	14	Jun-2011
Longfellow Wind Project **	Wind	40	Jun-2011
Middletown 12-15	Natural Gas	186	Jun-2011
Other Small Renewables *	Renewable	8	Jun-2011
Record Hill Wind **	Wind	51	Jun-2011
Rhode Island LFG Genco, LLC - ST	Landfill Gas	26	Jun-2011
Rhode Island LFG Genco, LLC - ST #2	Landfill Gas	11	Jun-2011
Ansonia Generating Facility	Natural Gas	60	Jun-2012
Dartmouth Power Expansion	Natural Gas	21	Jun-2012
New Haven Harbor Units 2, 3, & 4	Natural Gas	130	Jun-2012
Other Small Renewables *	Renewable	10	Jun-2012
Plainfield Renewable Energy	Wood Waste Solids.	38	Jun-2012
BFCP Fuel Cell	Natural Gas	13	Jun-2013
Highland Wind **	Wind	129	Jun-2013
Laidlaw Berlin Biopower	Wood Waste Solids.	59	Jun-2013
Northfield Mountain ***	Pump Storage	30	Jun-2013
Other Small Renewables *	Renewable	13	Jun-2013
Kleen Energy	Natural Gas	620	Jun-2014

* Includes wind, biomass, landfill gas, and photovoltaic
** Nameplate capacity reported
*** Uprate in capacity (units 2 - 4)

In addition to planned capacity additions per FCM, CRA modeled the construction of additional generic renewable resources that will be required to meet state specific RPS requirements. Table 6 shows the generic capacity additions. CRA forecasted renewable capacity additions based on current RPS levels for each state within the ISO-NE market as well as any projected revisions of the RPS levels. In identifying locations for the capacity, consideration was given to projects identified within the ISO-NE interconnection queue, noting that, based on historical data, only a fraction of projects currently in the queue have high probability of being completed. While the generic renewable capacity additions do not represent specific projects, the mix of technology types and locations is influenced by the mix of projects under development. Specifically, the new renewable capacity mix includes 700 MW of offshore wind, including the Cape Wind project and other offshore resources under development for Southern New England. Because there is significant uncertainty about whether sufficient renewable resources can be added in the timeframe required to meet RPS targets and whether all targets will remain at their current levels, the assumed build out is a

conservative assumption[12]. If fewer resources are added, the potential price impact of the NPT Line should be greater.

Table 6: Generic Capacity Additions to Meet RPS in New England (Name Plate MW)

Technology Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Wind	-	208	257	202	140	200	200	200	200	200	200
Offshore Wind	-	-	-	-	28	500	260	100	-	-	-
Biomass	-	-	150	125	47	-	-	-	-	-	-
Landfill Gas	-	2	20	-	-	-	-	-	-	-	-
PV	17	33	45	41	41	41	40	40	40	40	40
Hydro	-	-	7	1	-	1	-	1	-	1	-
Market Total	17	242	479	369	256	742	500	341	240	241	240

The capacity retirements assumed to take place in 2010 and beyond, based on accepted delist bids in the Forward Capacity Auctions include:

- Somerset 6
- Salem Harbor 1-2

This limited set of retirements is again a conservative assumption. Additional delist bids have been rejected based on reliability concerns. If those concerns are resolved, additional unit retirements are likely. Specifically, permanent delist bids have been filed for Salem Harbor 3 and 4 for FCA 5, and a delist request of Vermont Yankee, for which the Vermont legislature has voted to deny extension of an operating license, was rejected in FCA 4.

3.3.3. Fuel Prices

Long-term natural gas prices at Henry Hub were based on the Energy Information Administration's Annual Energy Outlook 2010 ("AEO 2010") forecast. Basis differentials to regional trading hubs were estimated based on NYMEX futures and historical data. Plant level delivered gas prices were forecasted based on the historic relationships of local prices to hub prices. Prices were forecasted monthly, accounting for the pricing impacts of seasonal differences in supply and demand.

Monthly fuel oil prices were derived from forecasted crude oil prices and historical relationships between crude oil prices and refined products. Crude oil prices were based on the AEO 2010 forecast.

Annual average fuel prices are shown in Table 7.

[12] See, for example, ISO-NE's 2010 Regional System Plan (RPS), section 8.5.2.2, page 130 for a discussion on the attrition of wind projects from the ISO-NE's interconnection queue and the level of available wind projects necessary to meet RPS across New England.

Table 7: Fuel Price Assumptions for the Northeast ($/MMBtu, 2009 dollars)

Year	Henry Hub	Algonquin	Transco Zone 6 NY	NYC 1% FO6	NYC 0.3% FO6	NYC FO2
2015	6.30	6.97	6.96	11.50	14.01	20.14
2016	6.40	7.08	7.07	11.97	14.58	20.94
2017	6.41	7.09	7.08	12.34	15.05	21.59
2018	6.46	7.14	7.13	12.75	15.54	22.28
2019	6.53	7.21	7.21	13.01	15.86	22.73
2020	6.66	7.35	7.36	13.24	16.15	23.12
2021	6.76	7.46	7.47	13.40	16.35	23.40
2022	6.95	7.66	7.68	13.58	16.57	23.70
2023	6.98	7.69	7.71	13.77	16.79	24.01
2024	6.93	7.64	7.66	13.94	17.00	24.30

3.3.4. Transmission Topology and Planned Transmission Projects

The transmission topology used for CRA's analysis is based on a power system model developed by the Eastern Interconnection Reliability Assessment Group (ERAG). CRA used ERAG's 2009 series representation of 2013 summer conditions as a starting point. The case was modified to include expected transmission upgrades, including the NEEWS, MPRP, and the Scobie-Tewksbury line in New England, as well as major transmission projects in New York (M29 project) and PJM (TrAIL, PATH, Branchburg-Hudson, and Susquehanna-Roseland). CRA modeled the Scobie-Tewksbury line to reflect the reliability need for North-to-South transmission upgrades in New England noted in ISO-NE's long-term planning studies. Specifically, ISO New England's 2010 RSP lists the Scobie-Tewksbury line and the Seabrook-Ward Hill line as transmission alternatives to address reliability issues in the Greater Boston area. Both projects are expected to have a comparable impact on the transfer capabilities across the New England power system.

The NPT project includes an HVDC converter station in Franklin, NH and a 345 kV radial AC line to the existing Deerfield substation. For modeling purposes CRA assumed a power delivery directly at Deerfield.

3.3.5. Transmission Interface Limits

Based on ISO-NE's recent Regional System Plans (2009 RSP and 2010 RSP) and the MPRP study in support of the proposed plan application[13], CRA used the following limitations

[13] For N-1 limits see ISO New England's 2009 Regional System Plan, table 9-1 on page 112; available at: http://www.iso-ne.com/trans/rsp/2009/rsp09_final.pdf. For N-1-1 limits see ISO New England's 2010 Regional System Plan, explanations to Table 5-1 on page 54; available at: http://www.iso-ne.com/trans/rsp/index.html. The Northern New England-Scobie interface limit is based on the limitations stated in CRP's Maine Power Reliability Program, Proposed Plan Application, Analyses, Final Draft Report, Revision 3, June 9, 2008, table 5-11, page 78; available at: http://www.iso-ne.com/committees/comm_wkgrps/relblty_comm/relblty/mtrls/2008/jun172008/a2_3_mprp_final_draft_report_6_9_08.pdf

for major transmission interfaces in New England for the year 2015 and beyond. Except for Boston Import, CT Import, and SWCT Import, these limitations reflect single contingency ("N-1") planning limits. Reflecting ISO-NE operations, CRA assumed operational limitations ("N-1-1" limits) for Boston Import, CT Import, and SWCT Import interfaces. The maintenance of adequate operating reserves is critical in these transmission zones and allowable power transfers into these zones reflect the scenario that a first contingency could potentially be followed by a second contingency, increasing the amount of local generation that needs to be available to ensure reliable system operations.

Based on NPT engineering estimates the Scobie-Tewksbury 345 kV line is expected to increase the North-South interface capacity by an additional 700 MW, increasing the limit to 3,400 MW.

Table 8: New England Transmission Interface Limits

Interface	Limit (MW)
Orrington-South	1,200
Surowiec-South	1,150
Maine-NH	1,475
Northern New England-Scobie	3,080
North-South	3,400
Boston Import	3,700
East-West	3,500
CT Import	2,500
SWCT Import	2,300
NOR Import	1,650

3.3.6. Environmental Policy Assumptions

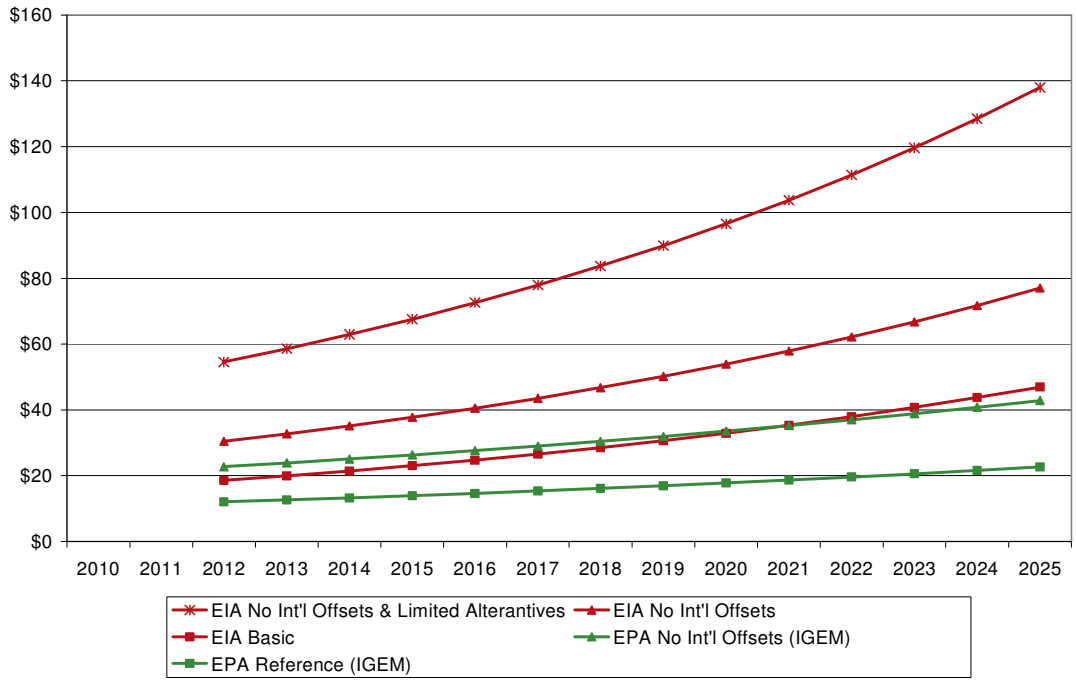
Due to the large degree of uncertainty in form and timing of future environmental policy under draft EPA rules, CRA has modeled the Clean Air Interstate Rule (CAIR) currently in effect, including scheduled tightening of the emissions restrictions, but no additional changes to the policies governing release of airborne emissions. In terms of the impact of NPT project, this assumption is likely conservative, as EPA is currently in the process of drafting environmental regulations that will ultimately replace CAIR with what are likely to be more stringent regulations. Estimated allowance prices are based on the results of CRA's North American Electricity and Environment Model (NEEM) for CAIR and are shown in Table 9.

Table 9: Emission Price Assumptions ($/ton, 2009 dollars)

Year	CO_2	NO_x	SO_2
2014	10.00	1,027	374
2016	10.00	1,132	288
2018	10.00	1,248	318
2020	10.00	1,376	350
2022	10.00	1,517	386
2024	10.00	1,673	426

With regard to CO2 regulation CRA assumed a national carbon policy, starting in 2015 at $10/ton and remaining at that price level throughout the study horizon. This level reflects a moderate increase in the cost of carbon emissions over what is expected under the RGGI program currently in place for New England and other states in the Northeast, but a smaller increase than the prices expected under most potential federal carbon legislation. Figure 6 provides the CO_2 price projections by EPA and EIA under different scenarios. Given the time horizon of this study, some form of federal policy is reasonably likely to be in place before the end of the analysis period, creating the potential for costs well above $10/ton. Hence, $10/ton provides a reasonable assumption, likely falling in the lower end of the range of potential long-term outcomes.

Figure 6: EPA and EIA Projections of CO_2 Prices under Various Scenarios (2009 dollars)



3.4. Modeling Approach for Québec Exports

Table 10 shows the assumed transfer capacities between the HQ system and neighboring control areas, including New England[14]. Based on the maximum transfer capabilities and initial GE MAPS simulation results, CRA developed monthly energy targets for each HQ intertie that correspond to reported annual net export targets of HQ.[15] The targets were developed by considering the range of potential export opportunities among all hours and destination markets and choosing the set of hours/destinations that would maximize net revenue for Hydro Québec. The resulting hourly delivery quantities were then summed for each intertie on a monthly basis, providing a monthly target energy level for each intertie and each month. Given these monthly energy allocation and maximum flow levels for each tie, the hourly schedules were develop with the GE MAPS model in order to allow the model to optimize the resulting hourly utilization for each intertie. A schedule was developed separately for the baseline scenario and the scenario with the NPT Line in service. Flows across HQ's ties with Vermont and New Brunswick were modeled based on historical flow data. Table 11 shows CRA's modeling results for the annual net export targets for all HQ interties, while Table 12 and Table 13 provide a breakdown by individual intertie for the base line and the NPT case, respectively.

Table 10: Assumed Transfer Capacities across HQ interties (MW)

	Ontario	New York	New England Phase II	New England NPT
Export Capacity from HQ	2,800	1,500	1,400	1,200
Import Capacity to HQ	1,850	1,000	1,400	1,200

Table 11: Annual Net Export Targets (TWh)

	2015	2016	2018	2021	2024
HQ net exports	24.0	25.0	28.0	30.0	30.0

14 Assumed transfer capacities reflect expected operating limitations under normal system conditions. Operating limitations were derived from observed historical tie line operations, and tend to be lower than the thermal limitation of the interties.

15 The 2015 export target was taken from HQ's Strategic Plan 2009-2013, page 25, available at: http://www.hydroquebec.com/publications/en/strategic_plan/index.html. Export targets for subsequent years were derived from HQ's Environmental Impact Assessment Study - Romaine Complex - Volume I, December 2007, table 2-8, page 2-10, available in French at: http://www.hydroquebec.com/romaine/pdf/ei_volume01.pdf

Table 12: Annual Energy Targets for HQ Interties – Baseline Case without NPT Line (GWh)

	Ontario	New York	New Brunswick	New England Phase II	New England NPT	New England Highgate	Total HQ
2015	3,445	6,787	1,752	10,436	0	1,577	23,996
2016	3,902	7,044	1,752	10,724	0	1,577	24,999
2018	5,624	7,648	1,752	11,399	0	1,577	27,999
2021	6,613	8,387	1,752	11,670	0	1,577	29,999
2024	6,613	8,387	1,752	11,670	0	1,577	29,999

Table 13: Annual Energy Targets for Individual HQ Interties – with NPT Line (GWh)

	Ontario	New York	New Brunswick	New England Phase II	New England NPT	New England Highgate	Total HQ
2015	-120	4,170	1,752	8,967	7,654	1,577	23,999
2016	-99	4,539	1,752	9,278	7,954	1,577	25,001
2018	381	6,219	1,752	9,797	8,272	1,577	27,998
2021	1,641	5,853	1,752	10,326	8,851	1,577	30,000
2024	1,641	5,853	1,752	10,326	8,851	1,577	30,000

Note that a key assumption of this allocation approach for exports from Québec as well as CRA's analysis of congestion and LMP impacts is that total exports from Québec would remain constant between scenarios with and without the NPT Line in service. In reality, the additional transmission capacity provided by the NPT Line could lead to additional development of resources to support exports from Québec, leading to higher total exports in the case with NPT in service. With those additional resources, the reduction in congestion and LMPs would be greater, and additional fossil-fueled generation would be displaced, resulting in a larger reduction in gas demand and CO_2 emissions.

4. Results

4.1. Wholesale Energy Pricing Impact

Table 14 shows CRA's projections of the impact of the NPT Line on wholesale power prices at the Mass Hub. Over the simulated 10-year period, the NPT Line is expected to decrease the average Mass Hub price by $1.22-1.86/MWh. The overall decrease in power prices is largely driven by lower on-peak prices, as most of power sales between HQ and ISO-NE were scheduled during peak hours.[16] The decline in off-peak prices is less pronounced. In 2015, lower power imports across the existing Phase II connection during summer off-peak hours are projected to offset the price effect of power imports across NPT, leading to a slight increase in average off-peak power prices.

Table 14: Energy Price Impact, Mass Hub ($/MWh, 2009 dollars)

		2015	2016	2018	2021	2024
Base Case	**Peak (5x16)**	72.36	73.73	74.89	77.34	78.97
	Off-Peak	58.27	59.00	59.41	60.96	61.93
	All Hours	64.99	66.00	66.79	68.77	70.06
NPT	**Peak (5x16)**	69.76	70.92	71.67	74.37	75.92
	Off-Peak	58.30	58.42	58.88	60.27	61.14
	All Hours	63.76	64.36	64.97	66.99	68.20
Delta	**Peak (5x16)**	(2.60)	(2.80)	(3.22)	(2.98)	(3.05)
	Off-Peak	0.03	(0.58)	(0.54)	(0.69)	(0.78)
	All Hours	(1.22)	(1.64)	(1.82)	(1.78)	(1.86)

Table 15 shows estimates of the average price impact of the NPT Line across New England RSP zones on a time-weighted basis that is indicative of the impact on locational marginal prices. Power prices in northern New England (BHE, ME, SME, NH, and VT) are expected to decline more sharply than power prices in southern New England. This is due to congestion across the New England North-South interface that occurs in some hours. The power that is delivered across the NPT Line into northern New England, along with generation from local sources, is sufficient in some hours to fully utilize capacity on the North-South transmission interface, resulting in lower prices in northern New England.

[16] Peak hours are defined as the periods from 7 AM through 11 PM, Monday through Friday. The remaining hours are classified as off-peak.

Table 15: Energy Price Impact, Simple Average by RSP Zone ($/MWh, 2009 dollars)[17]

	2015	2016	2018	2021	2024
BHE	(1.65)	(1.97)	(2.25)	(2.26)	(2.31)
ME	(1.70)	(2.04)	(2.31)	(2.35)	(2.47)
SME	(1.85)	(2.22)	(2.47)	(2.56)	(2.65)
NH	(1.88)	(2.25)	(2.49)	(2.58)	(2.68)
VT	(1.56)	(1.96)	(2.18)	(2.24)	(2.32)
BOS	(1.40)	(1.80)	(1.99)	(1.99)	(2.07)
NECMA	(1.34)	(1.75)	(1.94)	(1.90)	(2.00)
WMA	(1.11)	(1.52)	(1.70)	(1.62)	(1.71)
RI	(1.06)	(1.47)	(1.65)	(1.59)	(1.68)
SEMA	(1.15)	(1.55)	(1.73)	(1.70)	(1.78)
CT	(0.95)	(1.34)	(1.49)	(1.42)	(1.50)
SWCT	(0.85)	(1.23)	(1.37)	(1.28)	(1.36)
NOR	(0.82)	(1.19)	(1.33)	(1.23)	(1.31)
Total	(1.33)	(1.71)	(1.91)	(1.90)	(1.99)

4.2. WHOLESALE ENERGY COSTS FOR CUSTOMERS

Table 16 shows average decrease in wholesale power costs for customers in each RSP zone on a $/MWh basis. These load-weighted prices are representative of the average cost to load, as they account for the regional distribution and seasonality of the annual load shape.

[17] The ISO-NE RSP zones are defined as follows:

BHE	Northeastern Maine
ME	Western and central Maine/Saco Valley, New Hampshire
SME	Southeastern Maine
NH	Northern, eastern, and central New Hampshire/eastern Vermont and southwestern Maine
VT	Vermont/southwestern New Hampshire
BOS	Greater Boston, including the North Shore
NECMA	Northeastern Massachusetts/central Massachusetts
WMA	Western Massachusetts
RI	Rhode Island/bordering Massachusetts
SEMA	Southeastern Massachusetts/Newport, Rhode Island
CT	Northern and eastern Connecticut
SWCT	Southwestern Connecticut
NOR	Norwalk/Stamford, Connecticut

Table 16: Energy Price Impact, Load-Weighted Average by RSP Zone ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	(2.00)	(2.27)	(2.60)	(2.65)	(2.71)
ME	(2.05)	(2.35)	(2.70)	(2.77)	(2.92)
SME	(2.31)	(2.64)	(2.98)	(3.10)	(3.23)
NH	(2.32)	(2.64)	(2.98)	(3.11)	(3.23)
VT	(1.94)	(2.28)	(2.62)	(2.68)	(2.77)
BOS	(1.72)	(2.08)	(2.35)	(2.37)	(2.45)
NECMA	(1.68)	(2.04)	(2.33)	(2.31)	(2.40)
WMA	(1.37)	(1.74)	(2.03)	(1.95)	(2.03)
RI	(1.32)	(1.68)	(1.96)	(1.92)	(2.01)
SEMA	(1.40)	(1.75)	(2.02)	(2.02)	(2.10)
CT	(1.23)	(1.59)	(1.85)	(1.80)	(1.85)
SWCT	(1.10)	(1.47)	(1.70)	(1.64)	(1.69)
NOR	(1.10)	(1.47)	(1.71)	(1.63)	(1.68)
Total	(1.58)	(1.93)	(2.22)	(2.22)	(2.30)

Table 17 shows the corresponding projected energy cost savings for New England customers that are associated with the expected decline in energy prices. The wholesale costs to New England customers are expected to decrease by $206 million in 2015 and $327 million by 2024.

Table 17: Impact on Wholesale Energy Costs, by RSP Zone ($million, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	(4)	(4)	(5)	(5)	(6)
ME	(14)	(16)	(19)	(20)	(21)
SME	(7)	(9)	(10)	(10)	(11)
NH	(23)	(27)	(31)	(34)	(36)
VT	(14)	(16)	(19)	(20)	(21)
BOS	(45)	(55)	(63)	(66)	(70)
NECMA	(15)	(18)	(21)	(21)	(23)
WMA	(14)	(18)	(22)	(21)	(23)
RI	(15)	(19)	(23)	(23)	(25)
SEMA	(19)	(24)	(28)	(29)	(31)
CT	(19)	(24)	(29)	(29)	(30)
SWCT	(12)	(16)	(18)	(18)	(19)
NOR	(6)	(8)	(10)	(9)	(10)
Total	(206)	(254)	(297)	(306)	(327)

4.3. ISO-NE GENERATION MIX

The impact of the NPT Line on the 2015 New England generation mix is illustrated in Figure 7. The details for the remaining study years are given in Table 18. The power transfers across the NPT Line are expected to primarily displace generation of combined-cycle power plants. Generation from gas/oil-fired steam generators and peaking plants is also displaced. By lowering primarily the on-peak prices across New England, the NPT Line is expected to narrow the on-peak vs. off-peak spread, which leads to lower utilization of pumped storage

hydro facilities. Additionally, a portion of the additional net power imports from HQ are expected to be wheeled through to the NYISO control area.

Figure 7: Change in New England generation due to NPT Line, 2015

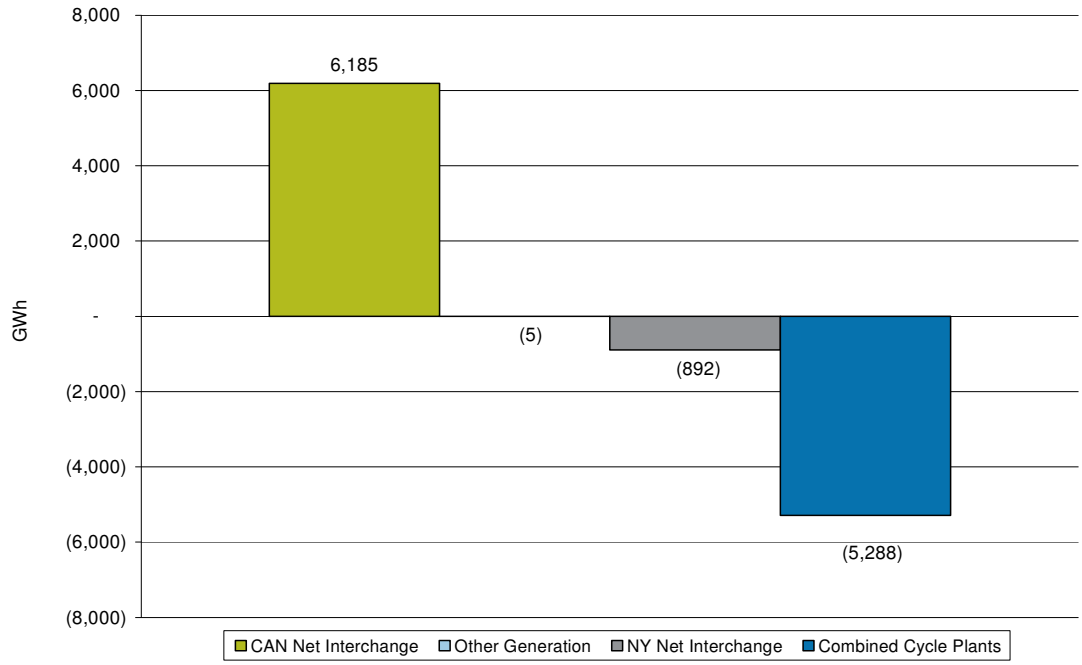


Table 18: Generation Impact by Generation Type (GWh)

(Negative values reflect a reduction in generation)

	2015	2016	2018	2021	2024
CAN Net Interchange	6,185	6,507	6,670	7,507	7,507
Combined Cycle	-5,288	-5,901	-6,157	-5,989	-5,925
NY Net Interchange	-892	-896	-1,038	-1,166	-1,072
Other Generation*	-5	289	525	-352	-510
Total	0	0	0	0	0

* includes changes in transmission losses and pumped storage losses

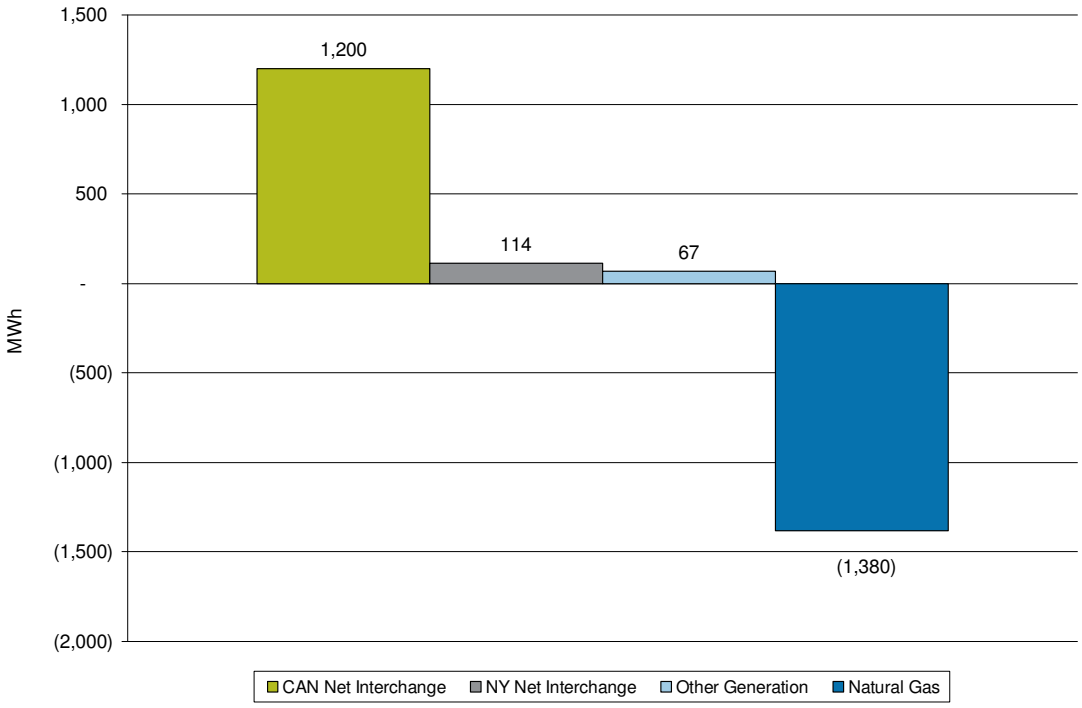
As shown in Table 19, the hydro-backed net imports from HQ across the NPT Line are expected to displace significant amounts of natural gas as a fuel for generating plants.

Table 19: Impact on Natural Gas Consumption in New England (Tcf)

	2015	2016	2018	2021	2024
Natural Gas Consumption (Tcf)	-24.7	-29.7	-25.0	-23.5	-21.8

New England's generation fleet relies heavily on natural gas for fuel. During the winter months – depending on weather – gas supply to New England may be tight, as gas demand for generation competes with demand for heating purposes. Gas supply disruptions during this period may jeopardize energy security. Figure 8 illustrates the impact of the NPT project on New England's generation dispatch during the 2015 winter peak hour. The 1,200 MWh of additional imports from HQ are projected to result in the displacement of 1,380 MWh of gas-fired generation, primarily combined-cycle generation, a reduction in exports to NYISO by about 115 MW, and a slight increase in other generation, largely related to pumped storage facilities. In effect, NPT is expected to provide a net 1,265 MW of additional security against gas disruptions in New England during the 2015 winter peak hour.

Figure 8: Generation Impact by Fuel, winter peak hour (MWh)



5. Conclusions

As detailed above, the addition of the NPT Project has a pronounced and continuing effect on the New England power market. The addition of 1,200 MW of transfer capability between Québec and southern New Hampshire creates several benefits, including:

- Reducing congestion between Québec and New England. At present, transmission limitations between these two systems limit the ability of Hydro-Québec to export its available energy to New England at times of greatest system need. Increasing the available transmission with the NPT Project allows Hydro-Québec to match deliveries with times of highest prices more closely, thereby having a greater benefit to New England consumers. This effect is best seen by the much greater reduction in wholesale electricity prices during peak periods (averaging $2.93/MWh over the modeled years) compared to the reduction in off-peak periods (averaging $0.51/MWh). This reduced congestion will allow imports from Québec to displace higher-cost fossil-fired generation in New England, resulting in wholesale savings for New England consumers of $206 million in 2015 to $327 million in 2024.
- Enhancing total imports of low-cost, zero-emissions energy to New England. Although the Hydro-Québec system today has a limited amount of energy available for export, projects in construction and in earlier development phases will allow Hydro-Québec to export substantial amounts of additional energy to New England. Without the NPT Project, however, the full amount of this additional power cannot be delivered directly to the New England market. The NPT Project allows an additional 5.3 TWh of Canadian imports into the New England market in 2015, rising to 6.4 TWh in 2024. CRA has conservatively assumed that currently projected growth in exports from Québec will occur whether or not the NPT Line is built. However, absent the NPT Line, these additional exports would be delivered during lower value periods with lower net revenues to Hydro Québec, which could result in delaying the development of the resources that will allow growth in total exports. If more projects supporting exports were developed as a result of the NPT Line, the impact of the line on imports, reduction in fossil-fueled generation in New England, and wholesale cost reductions would be greater.
- Improved fuel diversity resulting in greater system reliability. New England relies very heavily on natural gas for its electricity supply: 32 percent of annual generation.[18] More importantly, natural gas is on the margin during more than 60 percent of the pricing intervals.[19] New England has little gas storage, and New Englanders also rely heavily on natural gas as a heating fuel, so there is a potentially serious risk to the available fuel supply to the electric generation fleet on very cold winter days. The NPT Project would reduce the reliance on natural gas and so reduce the risk of service interruption to either heating or electric customers. Annually, the NPT is

[18] ISO New England Inc., *2009 Annual Markets Report*, p. 75.

[19] *Id.*, p. 80.

expected to free up 24.7 TCF on natural gas to the New England market which will increase reliability in both the power and natural gas markets.

APPENDIX A: DETAILED MODEL DESCRIPTION

An overview of the GE MAPS model was provided in Section 3.2 of this report. This appendix provides more detail about how the model combines its inputs to project hourly locational prices and unit generation, and discusses additional key input assumptions used in the model. The first section describes some assumptions implicit in the GE MAPS modeling approach (*e.g.*, how maintenance is scheduled, how operating reserve requirements are imposed), while the second details some of the fundamental input assumptions not discussed in the body of the report.

A.1 BASIC MODEL REPRESENTATION

The GE MAPS model is a security-constrained dispatch model that simulates the hourly chronological operation of an electricity market. Based on unit-level marginal cost bids, the model performs a least-cost dispatch subject to thermal and contingency constraints and calculates hourly, locational-based marginal prices for electricity. Nodal prices and unit level generation data can be aggregated to whatever level is desired (utility, region, state, *etc.*). Zonal load prices can be calculated either as load-weighted averages or as simple averages of locational prices. The GE MAPS simulation is consistent with the congestion management scheme currently utilized in ISO-NE and the other Northeast ISOs. The model's locational spot price calculation algorithm has been successfully benchmarked against the market price algorithm used in the New England market.[20]

CRA used a MAPS model footprint covering New England and neighboring regions for our analysis.[21] The model commits and dispatches generation to meet load in each of four market areas: NYISO, ISO-NE Ontario IMO, and PJM. In order to capture limitations in the coordination among these markets, economic imports from one area to another were only implemented if the resulting savings exceeded an economic hurdle.

A.1.1 Operating Reserves

MAPS accounts for spinning and non-spinning reserve requirements in its commitment and dispatch. The spinning reserve market affects energy market prices because the units that provide spinning reserve cannot produce electricity under normal conditions.[22] As a result, energy prices in MAPS are higher when reserve markets are modeled. Operating reserve requirements were modeled individually for each market area.

Only a limited portion of a generating unit's capacity can provide spinning reserves due to ramp-up constraints that prevent units from reaching their full capacity for delivering energy

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20 The actual ISO-NE transmission representation for an individual hour was input into MAPS, along with actual loads, imports and exports and generator bids. The locational prices calculated by the GE MAPS program matched those produced by the ISO-NE LMP system for those conditions.

21 Specifically, the footprint includes the NPCC, MAAC, and ECAR NERC regions.

22 Non-spinning reserve requirements rarely influence MAPS energy prices in areas like the eastern U.S., with a reasonably large supply of quick-starting gas turbines.

within the ten minute period required for operating reserves. Within the model, CRA specified a ramp rate for each unit and allowed it to hold operating reserves equal to the amount the unit can ramp in ten minutes.

A.1.2 Maintenance Scheduling for Thermal Generation Units

The GE MAPS model schedules maintenance of thermal generating units with the objective of levelizing the reserve margin across the weeks of each year.[23] CRA assumed that maintenance within each market area is scheduled such that reserves within the pool are levelized on an annual basis. For example, if a region's load peaks only in the summer, it will schedule little or no maintenance in that season; similarly, if a region's load peaks in both the summer and winter, it will schedule no maintenance in these two seasons.

A.1.3 Generation from Conventional Hydro and Pumped Storage Units

Hourly generation levels for each hydro unit were determined by the GE MAPS model for each of the scenarios and years modeled. The GE MAPS model takes monthly generation totals for each hydro unit together with limits on their maximum and minimum generation levels and schedules hydro generation against the load shape for the market area in which the unit is located. The GE MAPS model generally does not dispatch hydro generation to relieve transmission congestion. However, if the locational price at a hydro station bus is very low (less than $5/MWh), then MAPS backs down generation from that unit to relieve congestion; under these circumstances, backing down the hydro unit is the most economic and may be the only alternative to relieving congestion. Also, GE MAPS does not increase generation from hydro resources to relieve congestion, meaning that only thermal units are used for congestion management.

GE MAPS dispatches pumped storage units based on load and committed thermal generation in the surrounding region. The model approximates the price elasticity for each hour over the course of a week using the stack of available generating units in the surrounding region and finds the corresponding operating pattern for pumped storage units that minimize total production cost. The model honors the physical characteristics of each unit, including pumping and generating capacities, pumping efficiency and reservoir storage limits. When developing the schedule, the model does not directly account for transmission limits, but rather restricts the set of generators it considers to be available to ramp up for pumping or ramp down when the pumped storage units generate to those in the local region of each unit. Once the pumping and generating pattern has been developed, the model does honor all transmission constraints when meeting the schedule as part of the dispatch process.

A.2 Key Input Assumptions

CRA's analysis utilized our proprietary GE MAPS database, which has been compiled from the best available public data sources. The following is a list of the major components of the model. The list is followed by a description of the data sources for each component not discussed in the body of this report.

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23 The weekly reserve margin is capacity available during that week minus the week's peak load.

(1) Load Inputs

(2) Thermal Unit Characteristics

(3) Planned Additions and Retirements

(4) Fuel Price Forecasts

(5) Transmission System Representation

(6) Environmental Regulations

(7) Hydro Unit Output

A.2.1 Load Inputs

Peak loads and annual energy demands were based on forecasts reported by NYISO, PJM and ISO-NE. Since published data do not extend beyond 2019, forecasts were extended based on the projected growth over the reported forecast period. For New England peak load and annual energy demand, CRA relied on the 2010 ISO-NE CELT report, published in April 2010. The demand assumptions are shown in Table 4 in the body of this report. CRA adjusted the 2010 CELT forecast to allow passive demand response (PDR) to grow proportional to peak load. Tables A-1 and A-2 show CRA's PDR adjustments and the resulting peak load and energy forecasts.

Table A-1: ISO-NE Peak Load Reflecting Growth in PDR (MW)

Year	CELT Summer 50/50 Peak	CELT Summer Peak PDR	CRA Summer Peak PDR	CELT Summer 50/50 Peak Net PDR	CRA Summer 50/50 Peak Net PDR*
2011	27,660	784	784	26,876	26,876
2012	28,165	1,073	1,073	27,092	27,092
2013	28,570	1,073	1,088	27,497	27,482
2014	29,025	1,073	1,106	27,952	27,919
2015	29,450	1,073	1,122	28,377	28,328
2016	29,785	1,073	1,135	28,712	28,650
2017	30,110	1,073	1,147	29,037	28,963
2018	30,430	1,073	1,159	29,357	29,271
2019	30,730	1,073	1,171	29,657	29,559

* Peak loads after 2019 were assumed to grow by the 5-year CAGR

Table A-2: ISO-NE Demand Reflecting Growth in PDR (GWh)

Year	CELT Annual Energy	CELT Energy PDR	CRA Energy PDR	CELT Annual Energy Net PDR	CRA Annual Energy Net PDR*
2011	132,370	4,287	4,287	128,083	128,083
2012	134,005	5,895	5,895	128,110	128,110
2013	134,655	6,659	6,696	127,996	127,959
2014	136,060	6,659	6,798	129,401	129,262
2015	137,280	6,659	6,901	130,621	130,379
2016	138,500	6,678	6,989	131,822	131,511
2017	139,810	6,659	7,067	133,151	132,743
2018	141,175	6,659	7,143	134,516	134,032
2019	142,520	6,659	7,215	135,861	135,305

* Demand after 2019 was assumed to grow by the 5-year CAGR

Individual regional load shapes are based on actual 2006 zonal hourly load data as reported by the ISOs or utilities. The GE MAPS model adjusts each area's historical hourly load shape to fit the peak and annual energy numbers specified for that area for the year being modeled. The hourly load data created by that process for each area is then used as an input for the GE MAPS hourly simulation. Tables A-3 and A-4 show the peak load and annual energy assumptions for each zone in New England.

Table A-3: ISO-NE Peak Load by Zone, 2011-2024 (MW)

Annual Peak (MW)	BHE_AR	SME_AR	ME_AR	NH_AR	VT_AR	BOS_AR	NECMA_AR	SEMA_AR	WMA_AR	RI_AR	CT_AR	NOR_AR	SWCT_AR
2011	326	579	1,137	1,984	1,214	5,516	1,804	2,852	2,010	2,472	3,364	1,307	2,321
2012	325	578	1,142	2,019	1,216	5,530	1,847	2,876	2,036	2,493	3,377	1,308	2,345
2013	330	593	1,161	2,053	1,230	5,597	1,895	2,915	2,065	2,527	3,420	1,322	2,378
2014	335	607	1,181	2,102	1,254	5,670	1,944	2,953	2,099	2,565	3,467	1,337	2,412
2015	340	612	1,200	2,136	1,273	5,752	1,973	3,002	2,128	2,599	3,515	1,356	2,445
2016	340	622	1,215	2,170	1,287	5,819	1,997	3,036	2,157	2,628	3,548	1,370	2,469
2017	344	627	1,229	2,204	1,301	5,882	2,017	3,075	2,181	2,657	3,577	1,379	2,492
2018	344	636	1,244	2,233	1,315	5,939	2,036	3,108	2,205	2,691	3,610	1,394	2,511
2019	349	641	1,259	2,262	1,324	5,997	2,055	3,147	2,229	2,715	3,639	1,403	2,535
2020	352	649	1,274	2,295	1,338	6,060	2,077	3,185	2,256	2,745	3,670	1,415	2,558
2021	354	656	1,289	2,328	1,351	6,124	2,098	3,222	2,282	2,775	3,702	1,428	2,582
2022	357	664	1,304	2,362	1,365	6,188	2,120	3,261	2,309	2,805	3,734	1,440	2,605
2023	359	672	1,320	2,396	1,378	6,253	2,141	3,299	2,336	2,836	3,767	1,452	2,629
2024	362	680	1,336	2,431	1,392	6,319	2,163	3,339	2,363	2,867	3,799	1,465	2,653

Table A-4: ISO-NE Demand by Zone, 2011-2024 (GWh)

Annual Target Energy (GWh)	BHE_AR	SME_AR	ME_AR	NH_AR	VT_AR	BOS_AR	NECMA_AR	SEMA_AR	WMA_AR	RI_AR	CT_AR	NOR_AR	SWCT_AR
2011	1,870	3,149	6,617	9,604	6,937	25,842	8,365	13,157	10,060	11,179	15,222	5,584	10,502
2012	1,872	3,157	6,634	9,680	6,925	25,788	8,461	13,194	10,103	11,190	15,113	5,532	10,457
2013	1,865	3,147	6,611	9,723	6,902	25,691	8,536	13,201	10,122	11,190	15,055	5,490	10,424
2014	1,884	3,184	6,677	9,875	6,984	25,920	8,671	13,318	10,225	11,307	15,176	5,526	10,514
2015	1,899	3,207	6,728	9,988	7,046	26,167	8,754	13,444	10,324	11,409	15,276	5,561	10,578
2016	1,913	3,231	6,780	10,112	7,104	26,410	8,839	13,566	10,427	11,502	15,378	5,601	10,649
2017	1,928	3,255	6,837	10,247	7,179	26,659	8,930	13,699	10,532	11,626	15,489	5,643	10,727
2018	1,947	3,288	6,904	10,391	7,248	26,920	9,022	13,832	10,637	11,754	15,604	5,684	10,810
2019	1,962	3,317	6,966	10,526	7,323	27,187	9,113	13,970	10,746	11,857	15,724	5,726	10,888
2020	1,978	3,345	7,027	10,665	7,394	27,448	9,205	14,104	10,855	11,972	15,838	5,767	10,967
2021	1,994	3,373	7,089	10,806	7,466	27,712	9,298	14,240	10,964	12,088	15,953	5,810	11,047
2022	2,010	3,402	7,151	10,948	7,539	27,978	9,392	14,377	11,075	12,205	16,069	5,852	11,127
2023	2,027	3,430	7,213	11,093	7,612	28,247	9,486	14,515	11,186	12,323	16,186	5,895	11,208
2024	2,043	3,459	7,276	11,239	7,686	28,518	9,582	14,655	11,299	12,443	16,303	5,938	11,289

A.2.2 Thermal Unit Characteristics

GE MAPS models generation units in detail, in order to accurately simulate their operational patterns and thereby project realistic hourly prices. The following characteristics are modeled:

- Unit type (steam, combined-cycle, combustion turbine, etc.)
- Full load heat rates and heat rate curves.
- Summer and winter capacities.
- Operation and maintenance costs.
- Forced and planned outage rates.
- Minimum up and down times.
- Quick start and spinning reserve capabilities.
- Startup costs.

Sources for thermal unit data include the EIA-411, EIA-867, and EIA-412 forms, the FERC Form 1, and the REA-12 forms. When unit-specific data were unavailable, we developed generic heat rate curves for different unit types based on available data for similar units. CRA specified unit forced and planned outage rates for each type based on an analysis of NERC's "Generating Availability Data System" data set.

A.2.3 Planned Additions and Retirements

Planned additions and retirements impact the fuel mix of installed capacity and the composition of plants on the margin. In the near-term, CRA added new non-renewable capacity to the model based only on existing projects that are currently under construction or

have an obligation to provide capacity under the FCM.[24] As discussed in the body of this report, new renewable capacity was added to capture the impacts of renewable portfolio standards. Additional generic new capacity was added in the longer term if needed to meet regional reserve requirements in each case.

A.2.4 Fuel Price Forecasts

The opportunity cost of fuel consumed for generation (i.e., or the current spot price of fuel) is generally the largest component of a unit's marginal cost bid. To project these variable fuel costs, we used forecasts of spot fuel prices at regional hubs, and further refined these based on historical differentials between price points around each hub. For oil and gas, we used estimates of the price of delivered fuel to generators on a regional basis, while for coal we used plant specific price forecasts. The derivation of fuel price forecasts is described in the body of this report.

A.2.5 Transmission System Representation

The GE MAPS commitment and dispatch accounts for the impact of designated transmission constraints. CRA implemented a set of transmission constraints for the model regions based on publicly available regional studies and specific transmission constraints listed in ISO documents. Specifically, the modeled constraints included:

- NERC flowgates throughout the model footprint.
- All major interfaces in New England, NYISO and PJM.
- Most frequently binding constraints in the ISO-NE, NYISO, and PJM markets, as determined by CRA based on data published on the ISO websites.

[24] As reported in Ventyx Energy Velocity Database.

APPENDIX B: DETAILED MODEL RESULTS

Table B-1: Simple Average LMP by RSP Zone – Base Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	64.62	65.44	66.15	67.78	68.97
ME	65.06	66.04	66.81	68.58	69.86
SME	64.86	65.88	66.73	68.67	69.93
NH	64.28	65.30	66.16	68.13	69.44
VT	64.46	65.43	66.20	68.06	69.13
BOS	64.96	65.99	66.82	68.87	70.23
NECMA	65.21	66.25	67.08	69.12	70.50
WMA	65.23	66.23	67.00	68.94	70.20
RI	65.09	66.11	66.91	68.92	70.23
SEMA	65.27	66.31	67.14	69.21	70.63
CT	64.98	66.02	66.86	68.89	70.14
SWCT	65.14	66.20	67.06	69.16	70.41
NOR	65.29	66.37	67.24	69.35	70.55
Total	64.96	65.97	66.78	68.74	70.02

Table B-2: Simple Average LMP by RSP Zone – NPT Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	62.97	63.48	63.90	65.51	66.67
ME	63.36	64.00	64.51	66.23	67.39
SME	63.01	63.66	64.26	66.10	67.28
NH	62.40	63.05	63.68	65.55	66.76
VT	62.90	63.47	64.01	65.82	66.81
BOS	63.56	64.18	64.83	66.88	68.16
NECMA	63.87	64.50	65.14	67.22	68.50
WMA	64.11	64.71	65.31	67.32	68.49
RI	64.03	64.64	65.26	67.32	68.54
SEMA	64.11	64.77	65.41	67.52	68.85
CT	64.03	64.68	65.36	67.47	68.64
SWCT	64.29	64.97	65.69	67.88	69.05
NOR	64.47	65.17	65.91	68.12	69.23
Total	63.62	64.25	64.87	66.84	68.03

Table B-3: Load-Weighted Average LMP by RSP Zone – Base Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	66.39	67.22	67.96	69.77	71.05
ME	66.85	67.92	68.81	70.80	72.26
SME	67.11	68.27	69.26	71.43	72.90
NH	66.48	67.58	68.54	70.78	72.21
VT	66.43	67.45	68.30	70.32	71.46
BOS	66.92	68.02	68.96	71.23	72.72
NECMA	67.33	68.44	69.36	71.64	73.13
WMA	67.12	68.17	69.03	71.18	72.56
RI	66.99	68.06	68.96	71.22	72.64
SEMA	67.05	68.14	69.05	71.41	72.95
CT	67.53	68.64	69.58	71.93	73.32
SWCT	67.82	68.96	69.91	72.38	73.78
NOR	68.44	69.62	70.60	73.08	74.42
Total	67.13	68.22	69.14	71.40	72.82

Table B-4: Load-Weighted Average LMP by RSP Zone – NPT Case ($/MWh, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	64.39	64.95	65.35	67.12	68.34
ME	64.80	65.57	66.11	68.03	69.34
SME	64.80	65.63	66.28	68.33	69.67
NH	64.16	64.93	65.56	67.67	68.98
VT	64.49	65.17	65.68	67.63	68.70
BOS	65.21	65.94	66.60	68.87	70.26
NECMA	65.66	66.40	67.04	69.33	70.73
WMA	65.75	66.43	67.00	69.23	70.52
RI	65.68	66.37	67.00	69.30	70.63
SEMA	65.65	66.39	67.03	69.39	70.85
CT	66.30	67.05	67.73	70.13	71.46
SWCT	66.72	67.49	68.21	70.74	72.08
NOR	67.34	68.15	68.90	71.45	72.74
Total	65.55	66.28	66.92	69.18	70.52

Table B-5: Wholesale Cost of Serving Load in RSP Zones – Base Case ($million, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	126	129	132	139	145
ME	450	461	475	502	526
SME	215	221	228	241	252
NH	664	683	712	765	812
VT	468	479	495	525	549
BOS	1,751	1,796	1,856	1,974	2,074
NECMA	589	605	626	666	701
WMA	693	711	734	780	820
RI	764	783	810	861	904
SEMA	901	924	955	1,017	1,069
CT	1,032	1,056	1,086	1,147	1,195
SWCT	717	734	756	800	833
NOR	381	390	401	425	442
Total	8,752	8,971	9,267	9,842	10,321

Table B-6: Wholesale Cost of Serving Load in RSP Zones – NPT Case ($million, 2009 dollars)

	2015	2016	2018	2021	2024
BHE	122	124	127	134	140
ME	436	445	456	482	505
SME	208	212	218	230	241
NH	641	657	681	731	775
VT	454	463	476	505	528
BOS	1,706	1,741	1,793	1,908	2,004
NECMA	575	587	605	645	678
WMA	679	693	713	759	797
RI	749	763	787	838	879
SEMA	883	901	927	988	1,038
CT	1,013	1,031	1,057	1,119	1,165
SWCT	706	719	737	781	814
NOR	374	382	392	415	432
Total	8,546	8,717	8,970	9,536	9,995

Table B-7: Generation by Type – Base Case (GWh)

	2015	2016	2018	2021	2024
Peakers	389	383	429	451	491
Steam (Gas/Oil)	171	143	214	248	308
Combined Cycle	43,543	43,267	44,609	45,019	44,635
Pumped Storage	955	1,241	1,425	1,904	2,114
Steam (Coal)	18,836	18,709	18,583	19,081	19,137
Nuclear	36,455	36,899	36,541	37,330	37,507
Renewables	19,500	20,525	21,737	24,112	27,928
Hydro	5,290	5,290	5,290	5,290	5,290
CAN Net Interchange	13,281	13,567	14,256	14,508	14,533
NY Net Interchange	-216	66	245	65	-637
Total	138,203	140,091	143,328	148,008	151,308

Table B-8: Generation by Type – NPT Case (GWh)

	2015	2016	2018	2021	2024
Peakers	310	316	341	356	387
Steam (Gas/Oil)	108	82	131	150	204
Combined Cycle	38,255	37,366	38,452	39,030	38,710
Pumped Storage	847	1,106	1,448	1,804	1,971
Steam (Coal)	18,914	18,725	18,660	19,176	19,242
Nuclear	36,455	36,899	36,541	37,330	37,507
Renewables	19,500	20,524	21,737	24,112	27,928
Hydro	5,290	5,290	5,290	5,290	5,290
CAN Net Interchange	19,466	20,075	20,926	22,015	22,041
NY Net Interchange	-1,064	-871	-713	-975	-1,672
Total	138,081	139,512	142,813	148,289	151,608

Appendix H

Attestation

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Northern Pass Transmission LLC	)))	**Docket No. ER11-___-000**

ATTESTATION

James A. Muntz attests that he is President of the transmission business of Northeast Utilities' operating company subsidiaries and President of Northern Pass Transmission LLC and that, to the best of his knowledge, information, and belief, the cost of service materials and supporting data submitted as part of this filing which purport to reflect the books of Northern Pass Transmission LLC are true, accurate, and current representations of the company's books, budgets, or other company documents.

James A. Muntz

SUBSCRIBED AND SWORN to before me
on this 14th day of December, 2010.

Diane S. Faryniarz
Notary Public

My commission expires: 11/30/2014

Appendix I

Service List

Service List

Connecticut Department of Public Utility Control
10 Franklin Square
New Britain, CT 06051-2605

Maine Public Utilities Commission
18 State House Station
Augusta, ME 04333-0018

Massachusetts Department of Public Utilities
One South Station
Boston, MA 02110

New Hampshire Public Utilities Commission
21 South Fruit Street
Ste. 10
Concord, NH 03301-2429

Rhode Island Public Utilities Commission
89 Jefferson Blvd.
Warwick, RI 02888

Vermont Public Service Board
112 State Street, Drawer 20
Montpelier, VT 05620-2701

William M. Nugent, Executive Director
New England Conference of Public Utilities Commissioners, Inc.
50 Forest Falls Drive, Suite 6
Yarmouth, ME 04096